Appendix 7A

Black & Veatch 2013 Power Characterization Study

FINAL

2013 POWER STATION CHARACTERIZATION STUDY

B&V PROJECT NO. 179934
B&V FILE NO. 40.1200

REVISION 2

PREPARED FOR

Alliant Energy

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Acronym List

ABWR	Advanced Boiling Water Reactor
ac	Alternating Current
ACC	Air-Cooled Condenser
ACI	Activated Carbon Injection
ACP	American Centrifuge Plant
AD	Anaerobic Digestion
AF	Availability Factor
AFUDC	Allowance for Funds Used During Construction
AGR	Acid Gas Removal
ALWR	Advanced Light Water Reactor
AP1000	Westinghouse Advanced Passive 1000
AQC	Air Quality Control
AQCS	Air Quality Control System
ARRA	American Recovery and Reinvestment Act
a-Si	Amorphous Silicon
ASTM	American Society for Testing and Materials
ASU	Air Separation Unit
AVT	All-Volatile Method
AWEA	American Wind Energy Association
B&W	Babcock & Wilcox
BACT	Best Available Control Technology
BIGCC	Biomass Integrated Gasification Combined Cycle
BOP	Balance-of-Plant
CB&I-LC	Chicago Bridge & Iron, Lake Charles, LA
CCC	Carbon Capture and Compression
CCS	Carbon Capture and Sequestration
CCCT	Combined Cycle Combustion Turbine
CdTe	Cadmium Telluride
CEMS	Continuous Emissions Monitoring System
CF	Capacity Factor
CFB	Circulating Fluidized Bed
CH_4	Methane

CHP	Combined Heat and Power
CIGS	Copper Indium Gallium Selenide
CLFR	Compact Linear Fresnel Reflector
CMIS	Configuration Management information System
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COD	Commercial Operation Date
COLA	Combined Operating License Application
COS	Carbonyl Sulfide
CREB	Clean Renewable Energy Bonds
CSP	Concentrating Solar Power
CTG	Combustion Turbine Generator
CV	Containment Vessel
CWS	Circulating Water System
D&D	Decommission and Dismantle
DBI	Deutche Brennerstoffinstitute
dc	Direct Current
DC	Design Certification
DCD	Design Control Document
DCR	Design Certification Rule
DCS	Distributed Control System
DEH	Digital Electrohydraulic
DLE	Dry Low Emissions
DLN	Dry Low NO_x
DME	Dimethyl Ether
DNI	Direct Normal Insolation
DOE	Department of Energy
EGS	Enhanced Geothermal Systems
EOR	Enhanced Oil Recovery
EPC	Engineering, Procurement, and Construction
EPRI	Electric Power Research Institute
ERC	Energy Recovery Council
ESP	Early Site Permit
FBC	Fluidized Bed Combustion

FGD	Flue Gas Desulfurization
FIT	Feed-In Tariff
FOG	Fats, Oils, and Greases
FOR	Forced Outage Rate
FRP	Fiberglass Reinforced Plastic
G&A	General and Administrative Expenses
GE	General Electric
GHG	Greenhouse Gases
GHI	Global Horizontal Irradiance
GIS	Geographic Information Systems
GSU	Generator Step-Up
GTW	Gas Turbine World Handbook
H_2	Hydrogen
H_2S	Hydrogen Sulfide
HAP	Hazardous Air Pollutant
HCl	Hydrogen Chloride
HCN	Hydrogen Cyanide
HDCT	Heavy-Duty Combustion Turbine
Hg	Mercury
HGP	Hot Gas Path
HHV	Higher Heating Value
HP	High-Pressure
HPC	High-Pressure Compressor
HPT	High-Pressure Turbine
HRSG	Heat Recovery Steam Generator
HTHR	High Temperature Heat Recovery
HVAC	Heating, Ventilating, and Air Conditioning
I&C	Instrumentation and Control
IAEA	International Atomic Energy Agency
IB MACT	Industrial Boiler Maximum Achievable Control Technologies
IFC	Issued for Construction
IGCC	Integrated Gasification Combined Cycle
INEEL	Idaho National Engineering and Environmental Laboratory
IOU	Investor-Owned Utility

IP	Intermediate-Pressure
IPT	Intermediate-Pressure Turbine
ISBL	Inside the Battery Limit
ISFSI	Independent Spent Fuel Installations
IST	Integrated System Test
ITAAC	Inspection, Test, Analysis, and Acceptance Criteria
ITC	Investment Tax Credit
LFG	Landfill Gas
LHV	Lower Heating Value
LLRW	Low Level Radwaste
LNB	Low-NO_x Burners
LOCA	Loss-of-Coolant Accident
LP	Low-Pressure
LPC	Low-Pressure Compressor
LPT	Low-Pressure Turbine
LVRT	Low Voltage Ride-Through
LWR	Light Water Reactor
MACRS	Modified Accelerated Cost Recovery System
MACT	Maximum Achievable Control Technology
MEA	Monothethanolamine
MHI	Mitsubishi Heavy Industries
MISO	Midcontinent Independent System Operator
MMSD	Milwaukee Metropolitan Sewerage District
M-RETS	Midwest Renewable Energy Tracking System
MSR	Moisture Separator Reheater
MSW	Municipal Solid Waste
MTBE	Methyl Tertiary-Butyl Ether
MWMA	Municipal Waste Management Association
NAAQS	National Ambient Air Quality Standards
NEI	Nuclear Energy Institute
NGCC	Natural Gas Combined Cycle
NH_3	Ammonia
NI	Nuclear Island
NMTC	New Market Tax Credits

NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxides
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NSSS	Nuclear Steam Supply System
NTP	Notice to Proceed
NuStart	NuStart Energy Development, LLC
O&M	Operations and Maintenance
O_2	Oxygen
OEM	Original Equipment Manufacturer
OFA	Overfire Air
OSBL	Outside the Battery Limits
OSU	Oregon State University
PAC	Powder Activated Carbon
Pb	Lead
PC	Pulverized Coal
PF	Power Factor
PJFF	Pulse Jet Fabric Filter
PM_{10}	Particulate Matter (10 microns and less)
PPA	Power Purchase Agreement
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
PTC	Production Tax Credit
PTE	Potential to Emit
PV	Photovoltaic
PWR	Pressurized Water Reactor
QECB	Qualified Energy Conservation Bonds
QZAB	Qualified Zone Academy Bonds
R&D	Research and Development
RCL	Reactor Coolant Loop Piping
RCP	Reactor Coolant Pumps
RCS	Reactor Coolant System
RDF	Refuse-Derived Fuel
REAP	Rural Energy for America

REC	Renewable Energy Credits
REPI	Renewable Energy Production Incentives
RFS	Renewable Fuel Standard
RICE	Reciprocating Internal Combustion Engine
RIN	Renewable Identification Numbers
RPS	Renewable Portfolio Standards
RRC	Renewable Resource Credits
RV	Reactor Vessel
S	Sulfur
SA	Secondary Air
SCCT	Simple Cycle Combustion Turbine
SCPC	Supercritical Pulverized Coal
SCR	Selective Catalytic Reduction
SDA	Spray Dryer Absorber
SEC	Securities and Exchange Commission
SEGS	Solar Electric Generation Station
SES	Stirling Energy Systems
SG	Syngas
SMR	Small Modular Reactor
SNCR	Selective Noncatalytic Reduction
SNPTC	State Nuclear Power Technology Corp.
SO_2	Sulfur Dioxide
SPC	Subcritical Pulverized Coal
SREC	Solar Renewable Energy Credits
SRP	Salt River Project
STG	Steam Turbine Generator
syngas	Synthetic Gas
TA	Technical Advisory
TVA	Tennessee Valley Authority
US DOE	US Department of Energy
US EPA	US Environmental Protection Agency
US NRC	US Nuclear Regulatory Commission
USCPC	Ultra-Supercritical Pulverized Coal
USDA	US Department of Agriculture

USGS	US Geological Survey
UWO	University of Wisconsin - Oshkosh
VOC	Volatile Organic Compound
Westinghouse	Westinghouse Electric Company, LLC
WHB	Waste Heat Boiler
WTE	Waste to Energy
WWTP	Wastewater Treatment Plant

Unit of Measure List

¢	Cent
$	Dollar
%	Percent
°C	Degrees Celsius
°F	Degrees Fahrenheit
Btu	British Thermal Unit
bhp-hr	Brake Horsepower-Hour
ft	Foot
ft^3	Cubic Feet
ft/sec	Feet per Second
h	Hour
hp	Horsepower
Hz	Hertz
in. HgA	Inches of Mercury, Absolute
kV	Kilovolt
kW	Kilowatt
kW-yr	Kilowatt-Year
lb	Pound
lbm	Pound Mass
lb/MBtu	Pounds per Million Btu
ltpd	Long Ton per Day
MBtu	Million British Thermal Units
MBtu/h	Million Btu per Hour
mg	Milligram
MW	Megawatt
MWe	Megawatt Electrical
MWh	Megawatt-Hour
MWt	Megawatt Thermal
ppm	Parts per Million
ppmv	Parts per Million by Volume
ppmvd	Parts per Million, Volumetric Dry
psia	Pounds per Square Inch, Absolute
psig	Pounds per Square Inch, Gauge
rpm	Revolutions per Minute
scf	Standard Cubic Feet
stpd	Short Ton per Day
ton	Ton (2,000 lbm)
tpd	Tons per Day

tpy	Tons per Year
yr	Year

1.0 Introduction

Black & Veatch was retained by Alliant Energy to provide an updated power station characterization study. This study replaces a previous study that was performed in 2010 and provides descriptions, estimates of performance, capital costs, operations and maintenance (O&M) costs, construction schedules, and cash flow summaries for various power generation technologies and plant sizes. Characteristics are provided for the following technologies and sizes:

Fossil Fired Technologies

- Simple Cycle Combustion Turbine (SCCT) and Reciprocating Internal Combustion Engine (RICE):
  - 1x0 General Electric (GE) LMS100PA.
  - 1x0 GE LM6000PH.
  - 1x0 GE 7F 5-Series (formerly 7FA.05).
  - 6x0 Wartsila 18V50SG RICE.
- Combined Cycle Combustion Turbine (CCCT):
  - 1x1 GE 7F 5-Series.
  - 2x1 GE 7F 5-Series.
- Advanced Coal:
  - Ultra-supercritical Pulverized Coal (USCPC) 663 MW_{gross}, 600 MW_{net}.
  - USCPC, 663 MW_{gross}, 420 MW_{net} with carbon capture.
  - 2x1 Integrated Gasification Combined Cycle (IGCC), 600 MW.

Nuclear Energy Technologies

- Westinghouse Advanced Passive 1000 (AP1000).
- Small Modular Reactor (SMR).

Renewable Energy Technologies

- Wind.
- Solar:
  - Solar photovoltaic (PV).
  - Solar thermal electric.
- Solid biomass:
  - Direct fired.
  - Co-firing.
  - Biomass IGCC.
- Biogas:
  - Anaerobic digestion.
  - Landfill gas (LFG).
- Biofuels:
  - Ethanol.
  - Biodiesel.

- Waste to energy (WTE):
  - Mass burn.
  - Refuse-derived fuel (RDF).
- Hydroelectric.
- Geothermal.

Characteristics as summarized in the following sections are provided as part of this study.

1.1 TECHNOLOGY DESCRIPTIONS

Technology descriptions are provided for each of the options. The technology descriptions are summary level and provide a general overview of technology status and process. The overview information was based on Black & Veatch in-house data from past Black & Veatch projects and conceptual engineering studies. The data have been supplemented with nonproprietary data collected from technology providers and publicly available literature.

1.2 PERFORMANCE ESTIMATES

Performance estimates are provided for each of the options, based on a summer and winter dry bulb ambient temperatures of 95° F and 20° F, respectively. The performance estimates are based on the defined technical assumptions and proposed technology, sizes, and configurations. Assumptions include cycle arrangements, air quality control system (AQCS) requirements, fuel characteristics, heat rejection, and condenser performance assumptions, where applicable. The assumption basis from the 2010 report was reviewed and revised as needed.

1.3 POWER PLANT CAPITAL COST ESTIMATES

Order of magnitude capital cost estimates were developed for each of the options. The capital cost estimates were based on recent estimates for similar facilities and referenced from past and current Black & Veatch cost estimating experience and other market data for similar facilities. Cost estimates were not based on price quotations for equipment or construction. Rather, cost estimates were factored from reference plants by assuming factoring adjustments for scope differences between the reference plants and the plants being investigated. This method of cost estimating is typical for this level of study. In further studies, actual price quotations for equipment and construction could be obtained to further refine the estimates.

An engineering, procurement, and construction (EPC) cost estimate is exclusive of Owner's costs and predominately includes inside the battery limit (ISBL) costs. Potential types of Owner's costs, project development and outside the battery limit (OSBL) costs are presented in tabular format. Typical Owner's costs, as a percentage of the EPC cost are provided for each technology type. Refer to Section 2.4.

The EPC capital cost estimates are presented as an overnight cost in Q4 2013 US dollars and are reflective of an upper Midwestern greenfield plant site. Black & Veatch estimated the cost of construction contracts on the basis of upper Midwestern union labor and productivity rates. Total project cost estimates are also provided using an assumed Owner's cost allowance (percentage of EPC capital cost).

1.4 POWER PLANT OPERATING COST ESTIMATE

Black & Veatch has prepared order of magnitude O&M cost estimates for each of the options. The O&M estimates consist of fixed and non-fuel variable O&M costs. Black & Veatch has used O&M cost assumptions provided by Alliant Energy where applicable. In the absence of assumptions from Alliant Energy, Black & Veatch has provided assumptions which are reasonable for the project. Assumptions developed as a part of the estimating basis for the thermal performance and EPC capital costs are also directly applicable to the O&M cost estimates. The O&M cost estimates are provided in Q4 2013 US dollars.

1.5 PRELIMINARY PROJECT SCHEDULE AND DURATIONS

Preliminary project schedules are provided and presented in graphical bar chart format for each of the fossil and nuclear options. The preliminary project schedule includes milestones and project durations for the options. An overall estimate from a notice to proceed (NTP) to a commercial operation date (COD) is provided. Estimates of project schedules will be based on current labor and market conditions and reference from recent and ongoing Black & Veatch projects. For renewable technologies, project durations are provided.

1.6 PRELIMINARY CASH FLOW

Preliminary cash flow summaries are provided for the fossil and nuclear technologies. The cash flow summaries include incremental and cumulative cash flows for the project. The cash flow summaries are based on the construction schedules as described above.

2.0 Overall Study Basis Assumptions

An overall study design basis was developed to allow all technologies to be characterized on a consistent level. This section provides the overall study design basis that is common among all fossil, nuclear, and (as available) renewable technologies. Assumptions specific to each of the technologies, along with their technology characteristics, are provided in their respective sections. The assumptions include cycle arrangement, AQCS, and cost estimating considerations. The following subsections present the overall study design basis and assumptions, which consist of plant site location, meteorological assumptions, and fuel assumptions.

2.1 PLANT SITE METEOROLOGICAL ASSUMPTIONS

Characteristics were based on average-day summer and winter meteorological conditions that are representative of Alliant Energy's service territory. Table 2-1 provides the assumed plant site meteorological assumptions. See report sections for any exceptions to this table.

Table 2-1 Plant Site Meteorological Assumptions

LOCATION	UPPER MIDWESTERN GREENFIELD SITE
Elevation, feet above mean sea level	1,000
Hot-Day Dry-Bulb Ambient Temperature, °F	95
Hot-Day Relative Humidity, percent	60
Cool-Day Dry-Bulb Ambient Temperature, °F	20
Cool-Day Relative Humidity, percent	60

2.2 PLANT SITE LOCATION AND INFRASTRUCTURE ASSUMPTIONS

The following provides basic assumptions specific to the plant site location and Owner's cost interconnects to the plant site boundary:

1. Study characteristics are reflective of an upper Midwestern greenfield site. Renewable technology options would be sited at appropriate locations for the purpose of utilizing available renewable resources.
2. The existing plant site is assumed to be level and clear. No demolition or major site work would be required.
3. It is assumed that raw water is available at the plant site boundary. Potable water would be available by traditional means, either onsite wells or city water.
4. Electrical transmission for electric power generation distribution is assumed to be available at the plant site boundary.
5. The electrical interface is assumed to be at the high side of the generator step-up (GSU) transformer. Neither a substation nor a switchyard is included in the cost estimate.

6. The plant site would require standard infrastructure of onsite roads, which are included in the estimates. No offsite roads are included. Any required offsite roads should be included in the Owner's cost.
7. It is assumed that the site has sufficient area available to accommodate construction activities including, but not limited to, offices, lay-down, and staging.
8. Construction power and water are assumed to be available within the site boundary.
9. Offsite development should be included in the Owner's costs.
10. Protection or relocation of existing fish and wildlife habitat, wetlands, threatened and endangered species or historical, cultural, and archaeological artifacts is not included.

2.3 COST ESTIMATING ASSUMPTIONS

2.3.1 Common EPC Capital Cost Estimating Assumptions

Assumptions common among all technologies are provided in the following subsections. The assumptions describe direct and indirect costs associated with the capital costs, along with a description of the Owner's cost, which would be estimated separately from the capital cost. Assumptions specific to each of the technologies are also provided in their respective sections with the capital cost estimates.

2.3.2 Direct Cost Assumptions

The capital cost estimates were based on a turnkey EPC contracting methodology as described below:

1. All cost estimates are provided in Q4 2013 US dollars. Escalation for a given commercial operation date (COD) is not included.
2. Direct costs include the costs associated with the purchase of equipment, equipment erection, equipment supplier's technical advisory (TA) services during erection, and contractors' services.
3. An allowance for the transportation and delivery of equipment to the jobsite is included in the cost estimate.
4. Construction labor costs include an allowance for lost time resulting from inclement weather or other productivity issues.
5. A weighted average, composite labor wage rate reflective of an upper Midwestern site was utilized in developing the cost estimates. The composite rate includes all fringe benefits, payroll taxes, and social security. The composite total rate is a combination of the different craft that would work on the project.
6. Labor is assumed to be open shop.
7. A 50 hour work week is assumed for labor.
8. The cost estimates were based on a neutral cash flow to all contractors and equipment suppliers.

9. An allowance for operational spare parts was not included. The Owner’s cost allowance should include these parts.
10. Permitting and licensing fees are not included in the cost estimate. This should be included in the Owner’s cost allowance.
11. An Allowance for Funds Used During Construction (AFUDC) should be included in the Owner’s cost estimate.
12. Any offsite development should be included in the Owner’s costs. Refer to the Owner’s costs section for more information on the scope of Owner’s costs.

2.3.3 Indirect Cost Assumptions

Project indirect costs included in the estimates of the turnkey EPC contract include the following components:

1. Engineering.
2. EPC contractor’s contingency.
3. EPC contractor’s profit.
4. Performance bonds
5. Insurance.
6. Field construction management.

2.3.4 O&M Cost Assumptions

O&M costs exclude property tax, insurance premiums, and home office general and administrative expenses (G&A).

2.4 OWNER’S COSTS

Owner’s costs are not usually included in an EPC cost estimate and should be considered by the project developer to determine the total project cost. Owner’s cost items include OSBL physical asset costs, project development, and financing costs. In an EPC cost estimate, the scope boundary will be defined. Typically, it is established at the high side of the generator step-up transformer and “inside the fence,” or ISBL, costs. Interconnection costs can be major cost contributors to a project and should be evaluated in greater detail during a site selection study. Owner’s costs that could apply to fossil, renewable energy or nuclear projects are listed in Table 2-2. Owner’s costs that could apply only to nuclear technologies are listed in Table 2-3. The order of magnitude of Owner’s costs is project-specific and can vary significantly, depending upon technology and project-unique requirements. Owner’s costs typically fall within the ranges for the specified technologies outlined in Table 2-4. The Owner’s costs are expressed as a percentage of the escalated EPC project cost. The sum of the estimates of EPC project costs and Owner’s costs will equal the total estimated project cost, sometimes referred to as the Total Capital Requirement.

Table 2-2 Potential Owner's Costs

Project Development:
- Site selection study, site survey
- Meteorological tower
- Land purchase / options / rezoning
- Transmission & gas pipeline rights of way.
- Road modifications / upgrades
- Site cleanup, remediation
- Demolition
- Environmental permitting / offsets
- Public relations / community development
- Legal assistance
- Engineering studies – water and fuel supply, transmission.
- Market assessments
- Financial model

Utility Interconnections:
- Natural gas service
- Gas system upgrades
- Electrical transmission
- Raw or grey water supply
- Potable water supply
- Wastewater / sewer

Spare Parts and Plant Equipment:
- Air quality control systems materials, supplies, and parts
- Acid gas treating materials, supplies and parts
- Combustion turbine and steam turbine materials, supplies, and parts
- HRSG materials, supplies, and parts
- Gasifier materials, supplies, and parts
- Balance-of-plant equipment materials, supplies and parts
- Rolling stock
- Plant furnishings and supplies
- Operating spares

Owner's Project Management:
- Preparation of bid documents and selection of contractor/s and suppliers
- Provision of project management
- Performance of engineering due diligence
- Provision of personnel for site construction management

Plant Startup/Construction Support:
- Owner's site mobilization
- O&M staff training
- Supply of trained operators to support equipment testing and commissioning
- Initial test fluids and lubricants
- Initial inventory of chemicals / reagents
- Consumables
- Cost of fuel not recovered in power sales
- Auxiliary power purchase
- Construction all-risk insurance
- Acceptance testing

Taxes/Advisory Fees/Legal:
- Taxes
- Market and environmental consultants
- Owner's legal expenses:
  - PPA
  - Interconnect agreements
  - Contracts--procurement & construction
  - Property transfer

Owner's Contingency:
- Owner's uncertainty and costs pending final negotiation:
- Unidentified project scope increases
- Unidentified project requirements
- Costs pending final agreement (e.g., interconnection contract costs)

Financing:
- Development of financing sufficient to meet Project obligations or obtaining alternate sources of funding
- Financial advisor, lender's legal, market analyst, and engineer
- AFUDC
- Loan administration and commitment fees
- Debt service reserve fund

Miscellaneous
- All costs for above-mentioned Contractor-excluded items, if applicable

Table 2-3 Additional Potential Owner's Costs for Nuclear Technologies

Project Development: • Licensing activities (COL) **Spare Parts and Power Plant Equipment:** • NSSS materials, supplies, and parts • Radwaste (gaseous, liquid & solid) materials, supplies, and parts • Health physics materials, supplies, and screening machines (portal monitors, hand-helds) • Security personnel material, supplies and screening machines (explosive, metal, x-ray detection) **Nuclear Fuel Costs:** • Initial core (uranium, conversion, enrichment, fabrication contracts • Reloads	**Plant Startup/Construction Support:** • Supply of trained operators to support equipment testing and commissioning (pre-commissioning, HFT, low power, power ascension, final acceptance) • Supply of trained security to support nuclear fuel receipt, low power, and power ascension testing **Other Structures:** • Off-site TSC Response Center • Training Facility including Simulator • Security firing range • Cafeteria (food preparation capability) • Public visitation and community outreach facility • ISFSI dry spent fuel storage and casks • Public access to cooling lakes or parks

Table 2-4 Typical Owner's Cost, Percent of EPC Cost

TECHNOLOGIES	PERCENT
SCCT	25 – 30
CCCT	30 – 35
USCPC	40 – 45
IGCC	45 – 55
Nuclear	40 – 45
Renewables	10 – 55

Notes:

1. The above Owner's costs are expressed as a percentage of the escalated EPC project cost. The sum of the EPC project cost and the Owner's costs will give a total project cost.
2. The above Owner's cost estimates include AFUDC, which can be a large portion of the total Owner's cost.

2.5 RENEWABLE ENERGY INCENTIVES

A number of financial incentives are available for the installation and operation of renewable energy technologies. These incentives can substantially influence plant economics and profitability. The following discussion provides a brief list of existing incentives that are available to new renewable energy facilities. It should be noted that the intent of this section is to provide general information on available incentives; the availability of each incentive can be dependent upon qualification of a specific plant and/or ongoing legislative action.

2.5.1 US Federal Government Tax Incentives

The predominant federal incentive for renewable energy has been offered through the US tax code in the form of tax deductions, tax credits, or accelerated depreciation. An advantage of this form of incentive is that it is defined in the tax code and is not subject to a competitive application process, annual congressional appropriations or other limited budget pools (such as grants and loans). However, sunset provisions in the tax code (i.e., requirements that the energy generation facility is commercially online by a specified date) can impact project eligibility. Tax-related incentives include:

- Section 45 Production Tax Credit (PTC).
- Section 48 Investment Tax Credit (ITC).
- Accelerated Depreciation (i.e., Modified Accelerated Cost Recovery System [MACRS]).

In addition to the PTC, ITC, and MACRS, renewable energy projects may utilize New Market Tax Credits (NMTC), although NMTCs are subject to congressional budget allocations and competitive applications.

Additional detail regarding the PTC, ITC, MACRS, and NMTC are provided below.

2.5.1.1 Production Tax Credit (Section 45)

The Section 45 PTC is available to private entities that (1) produce electricity from various renewable energy technologies and (2) are subject to federal income taxation. The full tax credit, when enacted as part of the Energy Policy Act of 1992, was valued at 1.5 cents/kWh. The PTC is subject to annual inflation adjustment, and in 2013, it is equal to 2.3 cents/kWh for electricity generated by wind, geothermal, and closed-loop biomass. All other qualifying renewable energy technologies (e.g., open loop biomass, livestock waste, marine/hydrokinetic, landfill gas, and municipal solid waste) are eligible for "half" credit. The "half" credit was initially set at 0.75 cents/kWh; considering inflation adjustments, it is presently valued in 2013 at 1.1 cents/kWh.[1] (It is noted that solar projects are not listed among eligible technologies for the PTC; therefore, solar technologies are not eligible for either the full or half credit.) The PTC for current projects can be applied for ten years with certain carry forward and carry back provisions for unused credits.[2]

While the PTC has been beneficial to development of renewable energy projects in the US, there have been expirations and subsequent renewal of the PTC several times since 1999; it is currently set to expire on 31 December 2013. The uncertainty regarding renewal of the PTC during these years has resulted in "boom and bust" building patterns, particularly for wind projects. Most recently, the PTC was extended in January 2013 as part of the American Taxpayer Relief Act of 2012 (H.R. 8). Under H.R. 8, qualified projects must begin construction on or before 31 December 2013

[1] For 2013 calendar year, as published in the Federal Register (April 3, 2013): http://www.gpo.gov/fdsys/pkg/FR-2013-04-03/pdf/2013-07773.pdf.

[2] Database of State Incentives for Renewables & Efficiency, Federal Renewable Electricity Production Tax Credit, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US13F&re=1&ee=1, accessed October 22, 2013.

to be eligible for the PTC (rather than be "placed in-service" by the expiration of the PTC, as had been required in all previous iterations of the PTC.).

Major provisions of the Section 45 PTC are presented in Table 2-5.

Table 2-5 Major Production Tax Credit Provisions

RESOURCE	ELIGIBLE CONSTRUCTION START DATES	CREDIT SIZE*	SPECIAL CONSIDERATIONS
Wind	12/31/93 to 12/31/13	**Full**	
Biomass			
Closed-Loop	12/31/92 to 12/31/13	**Full**	Utilizing biomass fuels grown specifically for energy production (i.e., energy crops)
Closed-Loop Co-firing	12/31/92 to 12/31/13	**Full**	Utilizing energy crops; only allowed at specified coal power plants (including Ottumwa Generating Station)
Open-Loop	Before 12/31/13	Half	Does not include cofiring
Livestock Waste	Before 12/31/13	Half	>150 kW.
Geothermal	12/31/99 to 12/31/13	**Full**	
Marine and Hydrokinetic	10/22/04 to 12/31/13	Half	No new dams or impoundments; 150 kW-5 MW
Incremental Hydro	10/22/04 to 12/31/13	Half	Increased generation from existing sites
Landfill Gas	8/8/05 to 12/31/13	Half	
Municipal Solid Waste	10/22/04 to 12/31/13	Half	Includes new units added at existing plants
Notes:* All PTCs are inflation-adjusted and are equivalent to $23/MWh ("Full") or $11/MWh ("Half") in 2013.			

2.5.1.2 Investment Tax Credit (Section 48)

Similar to the PTC, the Section 48 ITC is available to private entities that (1) produce electricity from various renewable energy technologies and (2) are subject to federal income taxation. The ITC, in effect, offsets a portion of the initial capital investment in a project. The ITC may be applied to the capital cost of "energy property." For the various eligible renewable energy technologies (e.g., solar, wind, geothermal, combined heat and power [CHP], anaerobic digestion, municipal solid waste, small hydro, and marine), "energy property" is defined in Section 48 of the Tax Code.

Originally, investor owned utilities (IOUs) were not eligible to receive the ITC; however, the extension of the ITC passed in 2008 changed this wording to allow utilities to claim the ITC if they have sufficient tax burden. In addition, the American Recovery and Reinvestment Act (ARRA, or the "Stimulus Bill") expanded the eligibility to a broader range of resources, while the American Taxpayer Relief Act of 2012 modified the "placed in service" language to "begun construction by" (similar to the modification to the PTC). Provisions of the ITC (for various renewable technologies) are now as follows:

- Solar – Eligible solar equipment includes solar electric and solar thermal systems. For solar, the credit amount is 30 percent of the capital cost of "energy property" for projects that begin construction prior to 31 December 2016; for projects that begin construction following 31 December 2016, the credit drops to 10 percent of the capital cost of "energy property."
- Geothermal – Geothermal includes equipment used to produce, distribute, or use energy derived from a geothermal deposit. The ARRA increased the credit amount to 30 percent of the capital cost of "energy property" for units that begin construction by the end of 2013, except for heat pumps where the credit is limited to 10 percent through 2016.
- Wind – Projects eligible for the PTC are also ITC eligible. Units must begin construction by 31 December 2013.
- Biomass, LFG, hydro, and anaerobic digestion – Units must begin construction by 31 December 2013.

The current tax code does not allow claiming of both the PTC and the ITC; project developers must choose one or the other. For capital-intensive projects, the ITC is typically more attractive. For projects with lower capital cost and higher capacity factors and production, the PTC may be more advantageous. A 2009 analysis by Lawrence Berkeley Laboratory has quantified when the PTC or ITC is more attractive for a project investor.[3]

During a two year period from 2009 to 2011, qualified renewable energy projects (i.e., those projects eligible to utilize the ITC) were eligible to utilize a Section 1603 enabled cash grant from the US Department of the Treasury in place of the ITC. During this recessionary period, the Section 1603 cash grant allowed financing from organizations that might not have had the "tax appetite" (i.e., that were sufficiently profitable during this period) to utilize the tax credits. The Section 1603 cash grant program expired at the end of 2011 and has not been renewed.

While the ITC and the PTC may not be claimed for the same renewable energy project, the ITC may be utilized in conjunction with accelerated depreciation, as discussed further below.

2.5.1.3 Modified Accelerated Cost Recovery System (MACRS)

Section 168 of the Internal Revenue Code defines the Modified Accelerated Cost Recovery System (MACRS), through which certain investments can be recovered through accelerated depreciation deductions. There is no expiration date for the program. Under this program, certain power plant equipment may qualify for 5-year, 200 percent (i.e., double) declining-balance depreciation, while other equipment may also receive less favorable depreciation treatment.

Renewable energy property that is eligible to utilize MACRS includes solar (5-year), wind (5-year), geothermal (5-year), biomass (5-year) and solid waste (7-year). Typically, the majority of the project capital cost, but not all, can be depreciated on an accelerated schedule. However, for

[3] "PTC, ITC, or Cash Grant? An Analysis of the Choice Facing Renewable Power Projects in the United States.", report NREL/TP-6A2-45359, March 2009.

biomass, only certain portions of the plant receive MACRS. In addition for biomass, MACRS accelerated depreciation has been limited to plants with a capacity of 80MW and smaller, as that capacity size is part of the definition of a "small power production facility."[4]

The ARRA included a "bonus depreciation" allowance for most qualified renewable energy facilities that allowed 50 percent depreciation during the first year of operation. The American Taxpayer Relief Act of 2012 extended the deadline so that facilities that are placed in service by the end of 2013 are eligible. The accelerated depreciation law also specifies that the depreciable basis is reduced by the value of any cash incentives received by the project, and by half of any federal investment tax credits (e.g., the ITC). This provision has the effect of lowering the depreciable basis to 95 percent for projects that receive the 10 percent ITC and 85 percent for projects that take the 30 percent ITC.

2.5.1.4 New Market Tax Credits

New Market Tax Credits (NMTC) are credits for up to 39 percent of the qualified investment made in designated eligible areas which cover a significant portion of the US in both rural and urban areas. The NMTC is a broad development support program that is open to a range of investments, not just energy projects. NMTC projects should be of significant size (perhaps greater than $10 million in capital cost) to justify legal and transaction costs involved in the NMTC process.

While the specific eligibility requirements and application process is lengthy, the benefits can be substantial. As with the ITC/PTC, only taxable entities are eligible for the NMTC. Unlike the ITC/PTC, there are very complicated transaction rules, and not all projects that apply for NMTCs will be granted an award. The US Treasury holds allocation rounds, then reviews applications and selects awardees. Given the complexity of the qualification and application processes and the competitiveness for NMTCs, few renewable energy projects thus far have been able to utilize this incentive.

2.5.2 US Federal Government Non-Tax Related Incentives

A range of different types of non-tax incentives have been available to renewable energy project developers, but they tend to be much more limited in funding and of a shorter timeframe relative to tax-based incentives. The most widely used grant program in recent years, the Section 1603 cash grant, was passed as part of the ARRA bill but has since expired.

Many of the current non-tax related incentives are targeted at non-taxable entities such as municipally owned utilities. Government-owned utilities and other tax-exempt entities are not able to directly take advantage of tax incentives. Tax-exempt entities, however, do enjoy a number of other benefits when financing and/or operating renewable energy projects. The most obvious benefit is relief from federal and/or state income tax liability. Depending on project location and

[4] Depreciation tables refer to "small power production facilities" under §3(17)(C) of the Federal Power Act. An example of a plant size reference is an Office of Chief Council IRS Memorandum, 2011390F, found here; http://www.irs.gov/pub/irs-lafa/113901f.pdf.

local laws, payment of property taxes may also be reduced or eliminated. These entities are also able to issue tax-exempt debt, which carries lower interest rates than comparable corporate debt.

Non-tax incentive programs available today to support renewable energy include the following:

- US DOE Renewable Energy Production Incentives (REPI).
- Clean Renewable Energy Bonds (CREBs).
- Qualified Energy Conservation Bonds (QECBs).
- Rural Energy for America (REAP) Grants and Loan Guarantees.
- DOE Loan Guarantees.

The federal government has established two primary incentive programs for non-taxable entities, but neither is currently providing any support. These are the Renewable Energy Production Incentive (REPI) and Clean Renewable Energy Bonds (CREBs). Neither program is intended for privately-owned projects and both rely on limited congressional appropriations. Originally authorized in 1992, the REPI program was renewed by the Energy Policy Act of 2005 but has not received any funding allocation since 2009. The program provided payments to tax exempt entities, but the amount of funding was limited to a level provided during annual appropriations. In 2009 just one-third of payment requests received funding.

CREBs were introduced as part of the Energy Policy Act of 2005 as a response to the perceived problems with the REPI program. CREBs provided interest-free loans to public utilities (including rural electric co-ops), while providing tax credits to purchasers (the investors who buy the bonds). The program is patterned after the Qualified Zone Academy Bonds (QZABs) used to finance school improvements. Congress authorized $2.4 billion in bonds in 2008 and 2009. The IRS has typically indicated that projects would be funded starting with the smallest request and continuing with the next smallest until the funds are exhausted. This makes the CREB funds much more likely to be available for small projects. While it is unclear if the full funding allocation has been issued, there is no current pathway for obtaining CREBs. The application deadline for the most recent round of CREBs was 1 November 2010, and there is no indication of a new round of funding available in the near future.

A pathway to government support bond financing that is open is the Qualified Energy Conservation Bonds (QECBs). These are similar to CREBs in that they have been created to help state and local government entities finance energy efficiency and renewable energy projects. Once a QECB is issued, the government agency issuing the bond pays back the bond principal, while the bond holder receives a federal tax credit in lieu of traditional bond interest. Unlike CREB, there is no federal application process. Each state is allocated a cap for the amount of QECBs that may be issued, with a state agency being responsible for administration of the program. The states of Iowa, Minnesota and Wisconsin all have allocated QECBs available as of June 2013.[5]

[5] "Qualified Energy Conservation Bonds", Elizabeth Bellis, Energy Programs Consortium, Table 1C, page 22, June 2013.

The US Department of Agriculture's Rural Energy for America Program (REAP) promotes energy efficiency and renewable energy for agricultural producers and rural small businesses. Federal grants and loan guarantees are available through REAP. Congress must allocate grant funding on an annual basis, and the level of overall funding and funding per project is limited. For the most recent solicitation (April 2013), individual project grants for up to 25 percent of the project cost were available, provided that they did not exceed $500,000. Loan guarantees are not to exceed $25 million. If awarded both a grant and a loan guarantee, the combined total must not exceed 75 percent of the project's cost. The last deadline for entities to apply for grants and loan guarantees was 15 July 2013, although additional funding periods are currently being considered in the 2013 Farm Bill. To be eligible for funding, a utility would likely need to partner with a developer that would be eligible for funding under the REAP program for development of projects in rural locations. The limited funding levels and unique partnership requirements make the REAP program a complex funding source.

Under the Energy Policy Act of 2005 the DOE was authorized to issue loan guarantees for projects that reduced greenhouse gas emissions or demonstrated "new or significantly improved technologies." Large projects with a total cost greater than $25 million were the primary focus of this program. Loan guarantee recipients are required to repay loans in full at 90 percent of the useful life of the project (or 30 years, whichever is sooner). Currently there are no renewable energy project solicitations open; therefore, this program is not accepting applications.

2.5.3 Biofuels RFS2, and Renewable Identification Numbers (RINs)

The Federal Renewable Fuel Standard requires that transportation fuels sold in the US contain minimum volumes of renewable fuels. The second version of the requirement, known as RFS2, enacted in 2007, establishes four renewable fuels categories:

- **Conventional Biofuel:** Ethanol derived from corn is categorized as "conventional biofuel."
- **Biomass-Based Diesel:** Biomass-based diesel (i.e., biodiesel) is diesel fuel derived from vegetable oils (e.g., soybean oil) and animal fats (e.g., beef tallow), typically via a transesterification process.
- **Cellulosic Biofuel:** Any fuel derived from cellulose, hemicelluloses, or lignin is classified as "cellulosic biofuel." This includes biofuels derived from non-food feedstocks such as corn stalks, wheat straw, or wood.
- **Other Advanced Biofuels:** The category of Other Advanced Biofuels includes ethanol from sugarcane or sugar beets or Brazilian sugarcane ethanol. Biodiesel and cellulosic ethanol that exceed requirements in other categories may be applied to this category.

As of August 2013, RFS2 requirements are as listed in

Table 2-6.

Table 2-6 2013 RFS2 Requirements by Biofuel Type

BIOFUEL TYPE	VOLUME REQUIRED (MILLION GALLONS)(1)	PERCENTAGE OF FUEL PRODUCED OR IMPORTED(2)
Cellulosic biofuel	6	0.004
Biomass-based diesel	1,280	1.13
Advanced biofuel	2,750	1.62
Renewable fuel	16,550	9.74

Source: US Environmental Protection Agency, Regulatory Announcement, "*EPA Finalizes 2013 Renewable Fuel Standards*", EPA-420-F-13-042, August 2013. Accessed online at: http://www.epa.gov/otaq/fuels/renewablefuels/documents/420f13042.pdf.

Notes:
1. All volumes are ethanol-equivalent, except for biomass-based diesel, which is actual.
2. Estimated percentage of all gasoline or diesel fuel produced in or imported to the United States in 2013.

To gauge progress toward these goals, US EPA created the Renewable Identification Number (RIN) program that ties a number to each gallon of renewable fuel. RINs, along with or separate from their renewable fuel, are then bought and sold by obligated parties to meet requirements to blend the fuel with gasoline or diesel. The value of RINs varies as it is a market-based price. In general, requirements for biomass-based diesel, cellulosic biofuel and other advanced biofuels ramp up over the next several years.

2.5.4 Renewable Portfolio Standards

Renewable Portfolio Standards (RPS) have been used by a majority of US states to mandate that utilities include certain percentages of renewable generation within their generation portfolio. These policies have been a significant driver of US renewable power production. Most state legislatures establish an RPS goal for several future years and ask that the Public Utility Regulatory body in their state administer the program including tracking and compliance mechanisms.

2.5.4.1 Wisconsin RPS

Wisconsin's RPS is built around a statewide goal of 10 percent renewable generation by 31 December 2015. Each utility has a different requirement based on their past renewable production. The Wisconsin Public Service Commission will review progress towards this goal by 1 June 2016. Wisconsin uses the Midwest Renewable Energy Tracking System (M-RETS) to track utility compliance in REC and Renewable Resource Credits (RRC) acquisition.

2.5.4.2 Iowa RPS

Iowa has a very limited RPS which requires a combined total of 105 MW of renewable generation from its two investor-owned utilities (IOUs). This level was exceeded many years ago. In 2001, the governor of Iowa set a voluntary goal of 1,000 MW of renewable capacity to be developed within the state, and this goal also has been far surpassed.

2.5.4.3 Minnesota RPS

Effective 24 May 2013, Minnesota enacted a revised and increased level of renewable generation required in the portfolios of electric utilities in the state. For non-Xcel public utilities (Xcel must meet a higher standard) the following levels of renewable generation are required:[6]

- 12 percent by 31 December 2012.
- 17 percent by 31 December 2016.
- 21.5 percent by 31 December 2020 (including 1.5 percent solar).
- 26.5 percent by 31 December 2025 (including 1.5 percent solar).

Ten percent of the solar standard must be met with solar projects of 20kW or less. The Minnesota Public Service Commission administers compliance penalties, if needed.

2.5.5 Renewable Energy Credits (RECs)

Renewable Energy Credits (RECs) and Solar Renewable Energy Credits (SRECs) are often used as a compliance mechanism for utilities in states that have RPS requirements. The RECs or SRECs are created when a megawatt hour (MWh) of electricity is generated from a qualified renewable energy source. Both RECs and SRECs can be bought, sold, or traded (depending upon applicable rules) by utilities to meet RPS obligations.

SRECs are used in states that have an RPS with a specific solar requirement also known as a solar "carve out" or "set aside". SREC markets are significant in the northeast United States. State RPS compliance plans govern how utilities are allowed to purchase RECs and SRECs. There are many variations regarding which sizes and types of technologies qualify. There may be additional rules requiring that purchases qualify for compliance based on where the renewable power was produced. Examples of additional compliance requirements may include the following:

- Production in the utility service territory.
- Production in-state.
- Production in the Independent System Operator territory.
- Production in adjacent states.
- A REC "multiplier" may be given for preferred geographical locations or technologies.

There may be increasing challenges to these geographical restrictions from utilities and developers. The US Court of Appeals for the Seventh Circuit in a recent case mentioned that "Michigan cannot, without violating the commerce clause of Article I of the Constitution, discriminate against out-of-state renewable energy."[7]

[6] Database of State Incentives for Renewable Energy, Minnesota Renewable Portfolio Standard.
[7] *"7th Circuit Upholds Regional Cost Allocation for MISO Transmission Projects"*, Foley & Lardner LLP, http://www.foley.com/7th-circuit-upholds-regional-cost-allocation-for-miso-transmission-projects-06-19-2013/

In addition to the "Utility Compliance" REC markets which are largely state by state, there is a global "voluntary market" of RECs, in which a greater number of generators can participate. These RECs can be certified by an independent organization for certain criteria. Generally these RECs are much lower in price and may not cover the full cost of new renewable generation, but add value to older renewable energy plants. Examples of this market are the options to purchase RECs to "green your travel" and "offset your emissions" for conference travel or other activities.

2.5.6 Summary of Renewable Incentive Eligibility by technology type

Table 2-3 summarizes the incentives potentially available to projects utilizing various renewable energy technologies.

Table 2-7 Eligibility for Incentives (by technology) for Renewable Energy Generation Projects

TECHNOLOGY	PTC	ITC	MACRS	NMTC	RIN	REC
Wind	Yes	Yes	Yes	Yes	No	Yes
Solar PV	No	Yes	Yes	Yes	No	Yes
Solar Thermal Electric	No	Yes	Yes	Yes	No	Yes
Biomass – Direct-Fired	Yes	Yes	Yes	Yes	No	Yes
Biomass – Biomass IGCC	Yes	Yes	Yes	Yes	No	Yes
Biomass – Co-firing (Open-Loop)	No	No	No	Yes	No	Yes
Biogas – Anaerobic Digestion	Yes	Yes	Yes	Yes	No	Yes
Biogas – Landfill Gas	Yes	Yes	Yes	Yes	No	Yes
Ethanol	No	No	No	Yes	Yes	No
Biodiesel	No	No	No	Yes	Yes	No
WTE – Mass Burn	Yes	Yes	Yes	Yes	No	Yes
WTE – Refuse Derived Fuel	Yes	Yes	Yes	Yes	No	Yes
Hydroelectric	Yes	Yes	Yes	No	No	Yes
Geothermal	Yes	Yes	Yes	Yes	No	Yes

Abbreviations:
PTC – Production Tax Credit
ITC – Investment Tax Credit
MACRS -- Modified Accelerated Cost Recovery System
NMTC – New Market Tax Credits
RIN – Renewable Identification Numbers
REC – Renewable Energy Credits

3.0 Rules of Thumb

There are many potential permutations and combinations of plant configurations. Rather than attempting to provide an exhaustive list of estimates for these possible configurations, the following rules of thumb can be applied to the estimates for various technologies.

3.1 FLUE GAS DESULFURIZATION ALTERNATIVES

In past years, for a PC unit firing low-sulfur or western Powder River Basin (PRB) coal, a spray dryer absorber (SDA) flue gas desulfurization (FGD) system was typically assumed. However, recent trends in permitting and BACT analyses have shown more stringent sulfur control requirements, which can lead to use of wet FGD. In either case, for new units, there is a certain need for planning purposes to evaluate both dry SDA and a wet FGD. Wet FGDs can obtain higher SO_2 removal efficiencies over a wider range of coals. If an owner can narrow their permitted coal selection, an SDA may be approved in the permitting process.

As expected, wet FGD systems would have higher capital and annual O&M costs compared to a SDA in order to realize lower emissions rates. A wet FGD system would have substantially higher initial capital costs, higher auxiliary power requirements, and higher O&M requirements. However, a wet FGD system has an advantage of lower reagent (limestone) annual costs compared to the lime utilized as the reagent in an SDA system. The potential for gypsum and fly ash sales from a unit utilizing a wet FGD system could reduce the cost of fly ash and FGD byproduct disposal. Lime can cost as much as four to six times more than limestone per unit mass. Wet FGD can be expected to remove up to 99 percent of the sulfur dioxide (SO_2) produced by low-sulfur coal, while an SDA system will likely remove up to 95 percent.

Historically, an SDA/fabric filter combination has had lower total life-cycle costs for coal with up to 1.5 percent sulfur content and removal efficiencies of 95 percent or less. A fabric filter/wet FGD combination has had lower total life-cycle costs for coal with more than 2 percent sulfur content and removal efficiencies above 95 percent. As the required FGD efficiency has ratcheted upward, the “cross-over” coal sulfur level for the wet FGD system has decreased.

Wet FGD systems are installed downstream of the particulate collection. In contrast, SDA systems are installed upstream of the particulate collection and rely upon the particulate collection system to remove the solids byproduct of the SDA. This difference in the particulate control/FGD equipment train has a significant effect on the control of mercury emissions. An SDA/fabric filter combination can remove up to 25 percent of the total mercury emissions from the boiler without an additional PAC injection AQCS. In contrast, a fabric filter followed by a wet FGD system can be expected to remove 70 to 80 percent of the mercury without PAC. The mercury removal efficiency of both approaches is enhanced by the use of selective catalytic reduction (SCR) systems for the control of nitrogen oxides (NO_x) emissions. The estimated capital cost difference between an SDA and a wet FGD sulfur control system for a PC plant is provided in Table 3-1.

Table 3-1 Incremental Cost adder for Wet FGD for a PC Unit, 2013$

NET CAPACITY, MW	INCREMENTAL EPC COST REQUIREMENTS, $1,000		
600	125,000	To	155,000

These costs are dependent upon the sparing configuration utilized in the AQCS. This cost range accounts for the expense of redundancy that can be realized by installing the FGD system in incremental percentages of the total required capacity such as one 100 percent unit or two 50 percent units. For this estimate, we have assumed the use of one 100 percent absorber for the lower value and two 50 percent capacity absorber towers for the higher value.

3.2 HEAT REJECTION ALTERNATIVES

The three basic types of heat rejection systems used in large power plants include once-through cooling, wet evaporative cooling, and dry cooling. Once-through cooling requires a large body of water, such as a large river or a reservoir as a source of cooling water. For new projects, once-through cooling systems will not be a viable method because of environmental concerns. Wet evaporative cooling rejects circulating water heat by means of evaporation with cooling towers. Dry cooling employs an air-cooled condenser (ACC) to reject heat directly to the ambient air, eliminating the need for the condenser circulating water system.

In most instances where a modern power plant is not located next to a large body of water, a heat rejection system based on wet evaporative cooling employing wet mechanical draft cooling towers is a cost-effective choice. However, in water-limited regions, or for permitting reasons, an ACC can be used in lieu of the wet mechanical draft cooling tower.

Generally, using an ACC will adversely affect the unit's performance as these units are typically designed with higher steam turbine backpressures to reduce the high capital cost of the ACC. At higher ambient temperature, the performance impact is amplified. Specific unit performance impacts will be dependent on the specific site location. On an annual average basis, the reduction in generator output can be on the order of 2.5 to 3.0 percent. However, on a hot summer day the output can be reduced by as much as 10 percent because of an associated higher steam turbine back pressure. The ACC can be designed to reduce the impact on performance; however, this involves an increase in capital cost. An economic analysis should be performed to optimize this trade-off on a case-by-case basis.

Because of the large surface area required for effective heat exchange, an ACC will require much more plant area than a wet cooling tower. As an example, for the LMS100, the ACC will require about five times (5x) the space as compared to a wet cooling tower.

A benefit of an ACC system is that large water resources are not required. Typically, a unit with an ACC requires less than 10 percent of the water required for a unit with wet cooling. In a wet cooling tower system, large amounts of supplementary make-up water are necessary to replenish water lost through evaporation and blowdown. Additionally, the wet cooling tower system will require the injection of chemicals to control bio-fouling.

3.2.1 ACC Impact on PC and Combined Cycle Combustion Turbine Capital Costs

The estimated increase in initial capital costs for a 600 MW PC unit, and 1x1 and 2x1 combined cycle combustion turbine (CCCT) units with an ACC heat rejection system (dry case) is summarized in Table 3-2. These cost estimates are order-of-magnitude estimates inclusive of construction and project indirect costs but exclusive of owner's costs.

Table 3-2 Incremental Cost of using a Dry ACC, 2013$

CCCT OPTION	INCREMENTAL EPC COST REQUIREMENTS, $1,000		
600 MW PC	115,000	to	140,000
1x1 GE 7F 5-Series	22,000	to	33,000
2x1 GE 7F 5-Series	33,000	to	50,000

Notes:
1. ACC used for cycle heat rejection in lieu of a water-cooled condenser and cooling tower system.
2. Because an ACC would add additional back pressure on the steam turbine generator (STG), the net plant output is expected to decrease.

3.2.2 Heat Rejection System Considerations

Variable O&M costs are expected to be lower with an ACC compared to a wet cooling system by approximately 3 to 4 percent. The primary O&M costs for an ACC are associated with fan maintenance and cleaning of the finned surfaces on a dry system. There would be approximately three to four times as many fans and gearboxes on a dry system. In contrast, there are no circulating water pumps on a dry system, and the fans on an ACC operate in a less severe environment than the fans on a cooling tower. The ACC design does not require significant quantities of make-up water which often has to be treated in a clarifier/softener system. For a plant that uses wet cooling towers, the incremental quantity of make-up water for a 2x1 7FA combined cycle unit can be in the range of 1,500 to 2,000 gpm depending upon water quality and plant location.

For a wet mechanical draft cooling tower, the wooden structure would need to be repaired beginning approximately five years after initial operation. The expected life of a wooden cooling tower is 20 to 25 years. Cooling tower water nozzles may plug over time, and there will also be some maintenance required to keep the cooling tower fill clean (possibly including replacing damaged fill). Plant heat exchangers that are cooled with circulating water require periodic cleaning, which is more intensive than cleaning the fins on a dry cooling heat exchanger. The frequency and scope of structural repair work, fill cleaning (and possibly replacement), cooling tower nozzle cleaning, heat exchanger cleaning, and circulating water pump and pipe maintenance for a wet cooling system is highly dependent on water quality.

In addition, condenser tube cleaning maintenance is required on a wet system, which is not needed on a dry system. Depending on the initial tube material purchased for a wet cooling system, and the water quality of the circulating water, it is possible that the tubes in the condenser will need to be replaced during the life of the plant. Additional systems are required for circulating water makeup, blowdown, chemical treatment, etc., for a wet type system, each requiring some O&M. In addition to maintenance, there are costs associated with chemicals and makeup water.

For a plant that utilizes an ACC, the condensate system will probably need to include a pre-coat condensate polisher. The concern with ACCs is the tremendous amount of surface area and the resulting corrosion product that will pass to the boiler, if not polished. This is particularly troublesome for units that change load frequently, but even base load units have this concern during startup. If this polishing system is used in the plant, then additional costs for O&M will be realized. This system is typically not required on a unit that uses a wet cooling tower heat rejection system.

3.3 POTENTIAL COST REDUCTION OPPORTUNITIES

Several opportunities exist for reducing the capital and operating costs of the plants, as described in the following subsection.

3.3.1 Economies of Scale – Multiple Units

The benefits of economies of scale can be realized through facilities with multiple, identical units. The cost of Unit 1 and common facilities on a multiple identical unit site will be more than the cost of a stand-alone single unit. The higher cost is associated with the installation of the common infrastructure shared between the identical units. Identical-unit cost benefits are larger for coal-based technologies than for combustion turbine generator (CTG)-based technologies because of the higher cost and complexity of the commonly shared systems and plant infrastructure. The following rules of thumb can be applied for multiple identical unit sites.

3.3.1.1 Economies of Scale – Simple Cycle Combustion Turbine Plants

Economies of scale can also be realized for SCCT plants. However, the savings are minimal because these types of projects are less capital-intensive than both PC and CCCT plants. SCCT units are often installed at existing facilities where existing plant infrastructure and support systems can be used for the additional unit.

The cost of the first unit on a two-unit site will be slightly higher than that of a stand-alone single-unit site. This accounts for the increased capacity of common systems or the level of equipment redundancy and increased infrastructure. The increase in first-unit cost is expected to be in the range of 2 to 4 percent more than a stand-alone single-unit site.

For a two-unit site, assuming identical units, the second-unit cost will be in the range of 90 to 95 percent of the first-unit cost.

3.3.1.2 Economies of Scale – Combined Cycle Combustion Turbine Plants

Economies of scale can also be realized for CCCT plants. However, associated CCCT savings are less pronounced than those of PC plants since CCCT projects are less capital-intensive.

The cost of the first unit on a two-unit site will be slightly higher than that of a stand-alone single-unit site. This accounts for the increased capacity of common systems or the level of equipment redundancy and increased infrastructure. The increase in first-unit cost is expected to be in the range of 3 to 6 percent more than a stand-alone single-unit site.

For a two-unit site, assuming identical units constructed within 1 to 2 years of each other, the second-unit cost will be in the range of 88 to 92 percent of the first-unit cost.

3.3.1.3 Economies of Scale – Coal Plants

In most cases, a coal plant is designed for multiple units. Typically, the design calls for a minimum of two identical units, but can include more units. Capital-intensive projects (such as PC units) realize substantial savings when the site includes multiple units. The savings will vary depending on the number of units installed at the site, and the degree of interconnections and commonality of supporting systems.

The cost of the first unit on a two-unit site will be higher than for a stand-alone single-unit site. This accounts for the increased capacity of common systems or the level of equipment redundancy and increased infrastructure. This increase in first-unit cost is expected to be in the range of 6 to 8 percent compared to a stand-alone single unit.

For a two-unit site, assuming identical units constructed within 9 to 12 months of each other, the second-unit cost will be in the range of 75 to 80 percent of the first-unit cost.

The initial design of the plant should consider the economics of scale based on multiple units and/or unit size. The use of multiple identical units constructed in reasonable sequence will result in the greatest savings.

3.3.1.4 Economy of Scale – Unit Size

The cost per unit of output ($/kW) decreases as the output of the unit increases. This is primarily because there are many cost items that are independent (in varying degrees) of unit size. Some examples include engineering for project design and manufacturing, manufacturing and construction management, distributed control system (DCS), instrumentation, plant infrastructure, Owner's cost, etc. Other independent costs, such as the Owner's costs, which were not estimated in this study, make the economies of scale based on unit size more significant. Refer to Table 2-4 for suggested percentages of Owner's costs. Larger projects will generally have Owner's costs on the low end of the ranges provided.

3.3.1.5 Brownfield Site Unit Addition

Adding a unit to an existing (brownfield) site is generally more cost-effective than building a greenfield site. The cost savings can vary substantially depending on the capabilities of the existing infrastructure (coal handling, water supply, transmission, etc.) to serve the additional unit. A realistic rule of thumb is that adding a unit at a brownfield site will be 85 to 90 percent of the cost to install the unit at a greenfield site.

Notwithstanding these rules of thumb, other considerations (such as transmission system, switchyard, rail delivery, water availability, land availability, etc.) can offset the cost advantages of adding units at existing sites.

4.0 Simple Cycle Combustion Turbine (SCCT) and Reciprocating Internal Combustion Engine (RICE) Options

This section includes technology descriptions, performance and emissions, and cost characteristics for the following SCCT and RICE technology options:

- 1x0 GE LMS100PA.
- 1x0 GE LM6000.
- 1x0 GE 7F 5-Series.
- 6x0 Wartsila 18V50SG.

The following characteristics are addressed for each of the above options:

- Summary level technology descriptions.
- Thermal performance estimates including net plant output and net plant heat rate.
- AQCS assumptions based on probable Best Available Control Technology (BACT) emission requirements.
- The following cost estimates are provided in 2013$:
  - Order of magnitude overnight EPC capital cost estimates.
  - Fixed and non-fuel variable O&M.
- Typical high-level outage maintenance schedule.
- Preliminary project schedule and project durations.
- Preliminary cash flow summary.

4.1 TECHNOLOGY DESCRIPTIONS

CTGs are highly sophisticated power generating machines that operate according to the Brayton thermodynamic power cycle. A CTG generates power by compressing ambient air, heating the pressurized air to 2,000° F or more by burning oil or natural gas, and then expanding those hot gases through a turbine. The turbine drives both the air compressor and an electric generator. A typical CTG would convert 35 to 40 percent of the fuel energy to electric power. A substantial portion of the fuel energy is lost in the form of hot (900° F to 1,100° F) gases exiting the turbine exhaust. When the CTG is used to generate power and no energy is captured from the hot exhaust gases, the power cycle is referred to as a “simple cycle” power plant.

The maturity of CTGs has been widely established in both the domestic and international power generation markets. Advantages of SCCT projects include their low capital cost, short design and installation schedules, and wide availability.

CTGs are mass flow devices; thus, their performance changes with the ambient conditions. Generally, as temperatures rise, the CTG efficiency and output decreases because of the lower density of the air. To lessen the impact of this negative characteristic, most conventional power plants now include inlet air cooling systems to boost plant performance at higher ambient temperatures. In addition to ambient condition sensitivity to full-load performance, CTG emissions rates are typically higher at part load. This limitation has an effect on the turndown of the machine due to emissions limits. Aeroderivative CTGs tend to have better part-load operating performance than the larger, heavy-duty industrial CTGs. It is estimated that the output of a CTG can be reduced to approximately 50 to 60 percent load and still maintain emissions levels within the required limits.

4.1.1 SCCT Operational Description

The major components for an SCCT unit include the CTG(s) and balance-of-plant (BOP) equipment. SCCT plants are simple in arrangement and utilize few pieces of equipment. To meet project requirements, SCCT plants can be arranged with single or multiple CTGs. CTG can be used as building blocks to increase the capacity of a plant. A simplified schematic diagram depicting a 1x0 CTG arrangement is provided on Figure 4-1.

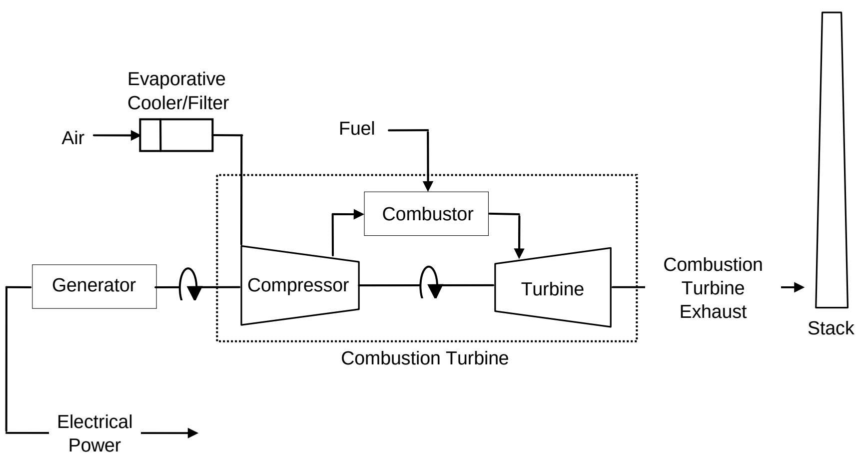


Figure 4-1 SCCT Schematic Diagram

4.1.2 GE LMS100PA

First introduced in 2003, the LMS100 is the first intercooled CTG system developed specifically for the power generation industry, combining the features of two technologies; heavy-duty CTG technology and aeroderivative CTG technology. The LMS100 delivers nominally 100 MW at 43 percent thermal efficiency (LHV). It is specifically designed for cyclic applications, providing flexible power for peaking needs.

The LMS100 features a heavy-duty low-pressure compressor (LPC) that was derived from GE Power Systems' MS6001FA heavy-duty CTG compressor; its core – which includes the high-pressure compressor (HPC), combustor, and high-pressure turbine (HPT) – was derived from GE Aircraft Engines' CF6-80C2 and CF6-80E1 aircraft engines. The design of the two-stage intermediate-pressure turbine (IPT) and five-stage power turbine is based on the latest aeroderivative CTG technology. The compressed air from the LPC is cooled in either an air-to-air or air-to-water heat exchanger (intercooler) and ducted to the HPC. The cooled flow requires less work from the HPC, increasing overall efficiency and power output. The cooler LPC exit temperature air, used for turbine cooling, allows higher firing temperatures, resulting in increased power output and overall efficiency. The LMS100 has the following characteristics:

- High full- and part-load efficiency.
- High availability.
- Low maintenance cost.
- Design for cycling applications.
- 10 minutes from start to full power output.
- Two NO_x combustion control models:
  - LMS100PA--Water injection for NO_x control.
  - LMS100PB--Dry low emissions (DLE) combustors for NO_x control.

The ISO performance characteristics for the GE LMS100PA and PB models, as referenced from the *2013 Gas Turbine World Handbook* (GTW), are provided in Table 4-1. It should be noted that the performance data shown in the GTW handbook is gross ratings based on ISO conditions at the generator terminals while firing natural gas and without consideration of inlet or exhaust pressure losses. Refer to the referenced document for more information.

Table 4-1 GE LMS100 Characteristics (GTW-ISO)

MODEL	GROSS PLANT OUTPUT, MW	GROSS PLANT HEAT RATE HHV (LHV), BTU/KWH	GROSS PLANT EFFICIENCY HHV (LHV), PERCENT (%)	EXHAUST TEMPERATURE, ° F
LMS100PA	103.5	8677 (7,815)	39.3 (43.6)	760
LMS100PB	99.4	8,541 (7,695)	39.3 (44.3)	789

HHV = Higher Heating Value.
LHV = Lower Heating Value.

4.1.3 GE LM6000PH

The GE LM6000PH is a two-shaft CTG engine derived from the core of the CF6-80C2, GE's high thrust, high efficiency aircraft engine. The CF6-80C2 has logged more than 185 million flight hours in the Boeing 747 and other wide-body aircraft. The LM6000 has more than 750 installed units of various models, with an average availability factor (AF) of 99 percent, and has accumulated more than 21 million operating hours.

The LM6000 consists of a five-stage LPC, a 14-stage variable geometry HPC, an annular combustor, a two-stage air-cooled HPT and a five-stage low-pressure turbine (LPT), and accessory drive gear box. It has two concentric rotor shafts. The LPC and LPT are assembled on one shaft, forming the low-pressure rotor. The HPC and HPT are assembled on the second shaft, forming the high-pressure rotor. The LPT, HPC, HPT and combustors of the LM6000 are virtually identical to the CF6-80C2. This use of flight-proven parts, produced in high volume, contributes to the relatively low initial capital cost and high operating efficiency of the LM6000.

The LM6000 uses the LPT to power the output shaft. By eliminating the separate power turbine found in many other CTGs, the LM6000 design simplifies the engine, improves fuel efficiency, and permits direct-coupling a generator for power generation. The CTG drives its generator through a flexible dry type coupling connected to the front, or "cold," end of the LPC shaft.

The LM6000 CTG generator set has the following characteristics:

- 10 minutes from start to full power output.
- Can be used for baseload, cycling, or peaking power.
- Compact, modular design.
- 21 million operating hours.
- More than 750 turbines installed.
- 99 percent documented AF.
- Available with water injection or dry low NO_x (DLN) combustors for NO_x control.
- Optional SPRINT (spray inter-cooling) for power augmentation.

The ISO performance characteristics for the GE LM6000, as referenced from the GTW Handbook, are provided in Table 4-2. The LM6000 PG and PH models shown below include water injection and DLE, respectively. It should be noted that the performance data shown in the GTW handbook is gross ratings based on ISO conditions at the generator terminals while firing natural gas and without consideration of inlet or exhaust pressure losses. Refer to the referenced document for more information.

Table 4-2 GE LM6000 Characteristics (GTW-ISO)

MODEL	GROSS PLANT OUTPUT, MW	GROSS PLANT HEAT RATE HHV (LHV), BTU/KWH	GROSS PLANT EFFICIENCY HHV (LHV), PERCENT (%)	EXHAUST TEMPERATURE, ° F
LM6000 PG	53.5	9,509 (8,582)	35.9 (39.8)	862
LM6000 PH	51	8,904 (8,020)	38.5 (42.8)	896

4.1.4 GE 7F 5-Series

The GE 7FA CTG, introduced in 1986, was the result of a multi-year development program using technology advanced by GE Aircraft Engines and GE's Corporate Research and Development Center. This program facilitated the application of technologies such as advanced bucket cooling techniques, compressor aerodynamic design, and new alloys to the F-class CTGs, enabling them to attain higher firing temperatures than previous generation machines.

In 2009, GE began offering updated versions of the 7FA. Newer model versions include compressor and performance enhancements and an advanced 3-D aerodynamic 14-stage compressor; they also integrate advanced technology from the GE 7FB model CTG. Upgraded versions of the 7FA were released for sale in 2009, with model designations of 7FA.03 and 7FA.04; each version supersedes the other with technology updates. The GE 7F 5-Series, also referred to as the “GE 7FA.05,” became available for shipment in 2011 and incorporates all planned performance enhancements and an advanced compressor design, which has increased the ISO output of the CTG from the past 7FA (7241) of 171 MW to 216 MW.

The 7F 5-Series combustion turbine is a single-shaft, single casing, advanced class machine. The compressor is based upon GE Aviation compressor technology practices. The 7F 5-Series compressor has a pressure ratio of 17.6 and consists of 14 stages.

For the 7F 5-Series, minor modifications to the DLN 2.6 combustion system were made to improve output and efficiency. Upgraded fuel nozzles allow for a higher fuel flow rate and the transition-piece cooling flow has been improved.

The turbine section of the 7F 5-Series includes three stages and builds on the recent 7FA.04 hot gas path advancements and FB technology and experience. The first and second stages of the turbine section include minor modifications to the 7FA.04 version hardware to increase the flow passing capability. The third stage utilizes a 7F Syngas design. The turbine casing remains unchanged.

The following summarizes the updated nameplate designations and CTG improvements:

- GE 7FA.03-This is the GE 7FA (7241) with compressor enhancements.
- GE 7FA.04-This is the GE 7FA.03 with Phase II performance enhancements.
- GE 7F 5-Series-This is the GE 7FA.04 with an advanced compressor.

The GE 7F 5-Series features a cold-end drive and axial exhaust, which is beneficial for combined cycle arrangements. The 7F 5-Series has a gross efficiency of 38.6 percent (LHV). The packaging concept of the GE 7F 5-Series features consolidated skid-mounted components, controls, and accessories. This standardized arrangement reduces piping, wiring, and other onsite interconnection work.

The 7F 5-Series utilizes the DLN 2.6 combustor and has retained the emissions characteristics of the 7FA (7241) model turbine, at 9 ppm NO_x, at full load. The ISO performance characteristics for the GE 7F 5-Series, as referenced from the GTW Handbook, are provided in Table 4-3. The GE 7FA has the following overall characteristics:

- More than 800 units in worldwide service, all models.
- More than 29 million operating hours and over 700,000 fired starts.
- First to achieve 96 percent availability.
- Model evolution was based upon the 7FA and 7FB experience.

It should be noted that the performance data shown in the GTW handbook is gross ratings based on ISO conditions at the generator terminals while firing natural gas and without consideration of inlet or exhaust pressure losses. Refer to the referenced document for more information.

Table 4-3 GE 7F 5-Series Characteristics (GTW-ISO)

MODEL	GROSS PLANT OUTPUT, MW	GROSS PLANT HEAT RATE HHV (LHV), BTU/KWH	GROSS PLANT EFFICIENCY HHV (LHV), PERCENT (%)
7F 5-Series	215.8	9,801 (8,830)	34.7 (38.6)
Note: Gross plant output shown is the ISO base rating including inlet and exhaust losses and shaft driven auxiliary losses.			

4.1.5 Wartsila 18V50SG

The 18V50SG is a turbocharged, four-stroke, spark-ignited, natural gas fired RICE. Unlike dual fuel reciprocating engines, the SG does not require liquid pilot fuel during startup and to maintain combustion. The 18V50SG utilizes 18 cylinders in a "V" configuration. Each cylinder has a bore diameter of 500 millimeters (19-11/16 inches) and a stroke of 580 millimeters (22-13/16 inches). Each engine operates at a shaft speed of 514 revolutions per minute. Individual cylinder computer controls and knock sensors for precise control of the combustion process, enabling the engine to operate more efficiently while minimizing emissions. The 18V50SG is based on the smaller 20V34SG model, with almost 400 engines in operation to date.

An 18V50SG power plant utilizing air cooled heat exchangers would require very little makeup water as the engines do not typically utilize inlet cooling for power augmentation or water injection for NO_x reduction.

Key attributes of the Wartsila 18V50SG include the following:

- High full- and part-load efficiency (~8300 Btu/kWh).
- Minimal performance impact based on hot ambient conditions.
- 10 minutes from start to full power.
- Minimal power plant footprint.
- Low starting electrical load demand.
- Ability to cycle on and off without impact of maintenance costs or schedule.
- Natural gas interface pressure requirement of 75 psig.

Wartsila offers a standard, pre-engineered six-engine configuration for the 18V50SG and the diesel-fired 18V50DF, sometimes referred to as a "6-Pack". The 6-Pack configuration has a net generation output of approximately 110 MW and ties the six engines to a single bus and step-up transformer. This configuration provides economies of scale associated with the balance of plant systems (e.g., step-up transformer and associated switchgear) and reduced engineering costs.

The ISO characteristics of the Wartsila 18V50SG, referenced from Wartsila data, are shown in Table 4-4.

Table 4-4 6x0 Wartsila 18V50SG Characteristics (ISO)

MODEL	GROSS PLANT OUTPUT, MW	GROSS PLANT HEAT RATE HHV (LHV), BTU/KWH	GROSS PLANT EFFICIENCY HHV (LHV), PERCENT (%)
18V50SG	110.1	8,370 (7,540)	29.6 (33.0)

4.2 PERFORMANCE ESTIMATES

This section presents estimates of thermal performance for the SCCT and RICE technologies. For the purpose of the evaluation, the technologies were evaluated on a consistent basis relative to one another. Arrangement assumptions specific to each SCCT and RICE case, which were used in the development of the estimates, are summarized in Table 4-5.

The performance estimates include net plant outputs and net plant heat rates when firing natural gas; these are summarized in Table 4-6. Performance estimates were generated on the basis of hot-day and cool-day ambient temperatures, as defined in Section 2.0. Hot-day, full load performance includes the effects of inlet evaporative cooling for power augmentation. Hot-day, full load emissions estimates are shown in Table 4-7.

The performance estimates are for new and clean units and do not include the effects of degradation. Specific AQCS, which is reflective of expected BACT requirements, were selected as the design basis for the purpose of developing performance and cost estimates; these are summarized in Table 4-5.

Table 4-5 SCCT and RICE Cycle Arrangement Assumptions

COMBUSTION TURBINE	1x0 GE LMS100PA	1x0 GE LM6000PH	1x0 GE 7F 5-SERIES	6x0 WARTSILA 18V50SG
Arrangement	1x0	1x0	1x0	6x0
Number of Combustion Turbines (or Recip. Engines)	1	1	1	6
Combustion Turbine (or Recip. Engine) Inlet Cooling	Evaporative	Evaporative	Evaporative	N/A
Fuel	Natural Gas	Natural Gas	Natural Gas	Natural Gas
NO_x Combustion Control	Water Injection	DLE	DLE	N/A
NO_x Post-Combustion Control	SCR	SCR	SCR	SCR
CO Post-Combustion Control	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst
Note: GE LMS100 design has inherently high CO emissions compared to the 7F 5-Series.				

Table 4-6 SCCT and RICE Thermal Performance Estimates

	AMBIENT TEMP.	COMBUSTION TURBINE LOAD LEVEL	NET PLANT OUTPUT, KW	NET PLANT HEAT RATE (HHV), BTU/KWH	NET PLANT HEAT RATE (LHV), BTU/KWH
1x0 GE LMS100PA	20° F	Full	102,700	8,580	7,730
		75%	76,900	9,180	8,270
		50%	51,100	10,480	9,440
	95° F	Base	87,800	8,990	8,100
		75%	64,300	9,730	8,770
		50%	42,700	11,160	10,050
1x0 GE LM6000 PH	20° F	Full	56,600	9,300	8,380
		75%	42,400	9,870	8,890
		50%	28,200	11,310	10,190
	95° F	Full	37,850	10,120	9,120
		75%	28,400	11,210	10,100
		50%	18,900	13,290	11,970
1x0 GE 7F 5-Series	20° F	Full	221,000	9,890	8,910
		75%	166,100	10,470	9,430
		50%	110,500	12,660	11,410
	95° F	Full	191,700	10,210	9,200
		75%	137,800	11,340	10,220
		50%	95,200	13,790	12,420
6x0 Wartsila 18V50SG	20° F	Full	108,400	9,580	8,630
		75%	81,200	10,250	9,230
		50%	53,900	11,700	10,540
	95° F	Full	92,700	10,040	9,050
		75%	67,900	10,860	9,780
		50%	45,100	12,460	11,230

Notes:
1. The evaporative cooler is assumed to be in operation for 95° F full load cases for CTGs.
2. Performance was based on an elevation of 1,000 feet and 60 percent relative humidity.
3. All performance was based on 100 percent methane with 0.2 grain of sulfur per 100 standard cubic feet (scf).
4. All data are expected and not guaranteed; they do not include allowances for margins.
5. Net output and heat rate were based on an assumed auxiliary load of 1.0 percent x full load. An additional 0.25 percent auxiliary load is assumed for the addition of SCR and CO catalyst. Net output is assumed to be reduced with the addition of SCR and CO catalyst. Net plant heat rate is assumed to be increased with the addition of SCR and CO catalyst.

Table 4-7 SCCT and RICE Emissions Estimates

	CT LOAD LEVEL	NO_X, AS NO_2		SO_2		CO	CO_2	PM_{10}
		ppm	lb/MBtu	ppm	lb/MBtu	lb/MBtu	lb/MBtu	lb/MBtu
1x0 GE LMS100PA	Full	5.0	0.017	8.0	6.00×10^{-4}	0.019	128	0.010
1x0 GE LM6000 PH	Full	5.0	0.017	8.0	6.00×10^{-4}	0.019	128	0.016
1x0 GE 7F 5-Series	Full	5.0	0.017	8.0	6.00×10^{-4}	0.019	128	0.009
6x0 Wartsila 18V50SG	Full	5.0	0.017	15.0	6.00×10^{-4}	0.036	128	0.019

Notes:
1. Emissions estimates are representative of hot-day, full load conditions. Evaporative coolers are assumed to be in operation for the hot-day, full load cases.
2. *ppm* is parts per million dry volume at 15 percent O_2.
3. All performance was based on 100 percent methane with 0.2 grains of sulfur per 100 scf. It is assumed that there are no Hg or Pb emissions for burning natural gas.
4. PM_{10} emissions shown are front and back half catch and include SO_2 and SO_3 oxidation.
5. All data are expected and are not guaranteed; they do not include allowances for EPC margins.
6. All emissions include the effects of SCR and CO catalyst.

4.3 CAPITAL COSTS

Market-based, order of magnitude overnight EPC capital and total project cost estimates were generated for each of the SCCT and RICE technologies; these are provided in Table 4-8. An EPC cost basis, exclusive of Owner's costs, was utilized. Typically, the scope of work for an EPC cost is the base plant, which is defined as being ISBL with distinct boundaries and terminal points. A total project cost estimate is defined as the EPC capital cost plus an Owner's Cost Allowance. The Owner's Cost Allowance was assumed as a percentage of the EPC capital cost.

The estimates were based on Black & Veatch proprietary estimating templates and experience. The order of magnitude estimates were prepared for the purposes of project screening, resource planning, comparison of alternative technologies, etc., and as such, are expected to be in the range of ±30 percent of actual project costs. The cost estimates were calculated using a consistent methodology between technologies, so although the absolute cost estimates are expected to vary within a band of accuracy, the relative accuracy between technologies is higher. The information is consistent with recent experience and market conditions, but as demonstrated in past years, the market is dynamic and unpredictable. Power plant costs will be subject to continued volatility in the future, and the estimates in this report should be considered primarily for comparative purposes.

The following listing provides general EPC capital cost estimating assumptions. The general assumptions identify the scope of supply included in the EPC capital cost estimate. Assumptions related to the development of the performance estimates also apply to the EPC cost estimates. Assumptions related to direct and indirect costs and Owner's costs were provided in Section 2.3. Overall site assumptions were also provided in Section 2.4. Refer to the following:

1. Costs estimates are provided for each of the following technologies:
    a. 1x0 GE LMS100PA.
    b. 1x0 GE LM6000PH.
    c. 1x0 GE 7F 5-Series.
    d. 6x0 Wartsila 18V50SG.
2. Each plant estimate will feature one CTG, with the exception of the six unit (6x0) Wartsila 18V50SG plant. The primary fuel will be natural gas.
3. The CTGs include an OEM standard sound enclosure. A bridge crane for servicing the CTG is not included. A bridge crane is included for servicing the six RICE units.
4. Spread footings are assumed for all equipment foundations. Stabilization of the existing subgrade is not anticipated.
5. The buildings, if any, are pre-engineered.
6. A sanitary sewer system is included.
7. Construction power is available at the site boundary.
8. Supply of natural gas will be available at the site boundary at the appropriate conditions that meet the CTG vendor requirements.

9. Fire protection will consist of the major equipment vendor's standard fire suppression system. Fire protection for major transformers will be a water deluge system.
10. Field erected tanks will consist of the following:
    a. Service/fire water storage tank.
    b. Demineralized water storage tank.

Table 4-8 SCCT and RICE EPC Capital Cost Estimates, 2013$

DESCRIPTION	1x0 GE LMS100PA	1x0 GE LM6000PH	1x0 GE 7F 5-SERIES	6x0 WARTSILA 18V50SG
Total Direct Costs, $1,000	78,000	39,700	100,800	98,200
Total Indirect Costs, $1,000	22,500	16,900	27,500	33,300
Estimated EPC Cost, $1,000	100,500	56,600	128,300	131,500
Net Plant Output, kW (1)	87,800	37,900	191,700	92,700
EPC Unit Cost, $/kW	**1,145**	**1,495**	**669**	**1,419**
Owner's Cost Allowance, percentage of EPC Cost	30	30	30	30
Owner's Cost Allowance, $1,000	30,200	17,000	38,500	39,500
Total Project Cost, $1,000	130,700	73,600	166,800	171,000
Total Project Cost, $/kW	**1,489**	**1,942**	**870**	**1,845**

Notes:
1. Based on the estimated thermal performance at hot-day ambient conditions and 100 percent load.
2. All EPC cost estimates are presented in 2013 dollars. The costs are order of magnitude estimates and are expected to be within ± 30 percent of the EPC cost.
3. EPC cost estimates are exclusive of Owner's costs.
4. The sum of the EPC cost and the Owner's cost will equal the total project cost. Owner's Cost is assumed to be 30 percent of estimated turnkey EPC Cost.

4.4 O&M COSTS

Order of magnitude estimates of annual average O&M expenses, including fixed and non-fuel variable annual expenses, were developed for each of the SCCT and RICE technologies. O&M costs are provided in both annual costs and on a unitized basis. Unitized fixed costs, those costs that tend to remain fixed and independent of the energy generated by the plant, are provided on a $/kW-yr basis. Unitized non-fuel variable costs, those costs that are dependent on the energy generated by the plant, are provided on a $/MWh basis. O&M costs were based on the assumed capacity factor (CF) and the estimated thermal performance at the hot-day ambient conditions and at 100 percent load with the evaporative cooler (if applicable) in service.

The O&M estimates were derived from order-of-magnitude estimates developed by Black & Veatch. Black & Veatch has utilized Alliant Energy's input in generating O&M cost assumptions as applicable. In the event that assumptions were not readily available from Alliant Energy, Black & Veatch provided assumptions that are reasonable for the project.

Assumptions specific to the development of the O&M cost estimates are provided in Table 4-9. Key O&M consumable costs were based on current market pricing. All assumptions relative to the development of the performance and capital cost estimates presented in previous sections are directly applicable to the O&M cost estimates.

Preliminary estimates of O&M expenses for each of the SCCT and RICE options are provided in Table 4-10.

Table 4-9 SCCT and RICE O&M Operating Assumptions

	1x0 GE LMS100PA	1x0 GE LM6000PH	1x0 GE 7F 5-SERIES	6x0 WARTSILA 18V50SG
Key O&M Costs, 2013$				
Staff, count	7	7	7	7
Operator Base Salary, $/yr	76,000	76,000	76,000	76,000
Labor Burden, percent	40	40	40	40
Operating Factors				
Capacity Factor, percent	5	5	5	5
Forced Outage Factor, percent	2.2	2.2	2.2	2.2
Availability Factor, percent	94	94	94	94
Service Factor, percent	5	5	5	5
Starts per Year, count	100	100	100	100
Outage Maintenance				
Borescope Inspection Duration, hours	12	12	12	N/A
Borescope Inspection Frequency, yrs/outage	1	1	1	N/A
CTG Combustion Inspection Duration, days	N/A	N/A	7	N/A
CTG Combustion Inspection Frequency, yrs/outage	N/A	N/A	4.5	N/A
CTG Combustion Inspection Interval,[3] hours/starts	N/A	N/A	12,000/ 450	N/A
CTG HGP Inspection Duration, days	N/A	N/A	15	N/A
CTG HGP Inspection Frequency, yrs/outage	N/A	N/A	9	N/A
CTG HGP Inspection Interval,[3] hours/starts	N/A	N/A	24,000/ 900	N/A
CTG Major Inspection Duration, days	N/A	N/A	30	N/A
CTG Major Inspection Frequency, yrs/outage	N/A	N/A	18	N/A
CTG Major Inspection Interval,[3] hours/starts	N/A	N/A	48,000/ 1,800	N/A
Aero CTG Hot Section Refurbishment Interval, fired hrs	25,000	25,000	N/A	N/A
Aero CTG Major Engine Overhaul Interval, fired hrs	50,000	50,000	N/A	N/A
RICE Major Maintenance, fired hrs	N/A	N/A	N/A	48,000[4]

Notes:
1. CTG = Combustion Turbine Generator.
2. HGP = Hot Gas Path.
3. Per GE GER-3620
4. The O&M cost estimates for the Wartsila 18V50SG RICE units were based on the maintenance schedule provided by Wartsila.

Table 4-10 SCCT and RICE Annual O&M Cost Estimates, 2013$

	1x0 GE LMS100PA	1x0 GE LM6000PH	1x0 GE 7F 5-SERIES	6x0 WARTSILA 18V50SG
Total Fixed Costs, $1,000	1,140	1,090	1,213	1,180
Total Variable Costs, 1,000	270	190	1,448	520
Net Plant Output, kW	87,800	37,850	191,700	92,700
Annual Net Generation, MWh	38,500	16,600	84,000	40,600
Fixed Costs, $/kW-yr	12.98	28.80	6.33	12.73
Variable Costs, $/MWh	7.01	11.45	17.24	12.81

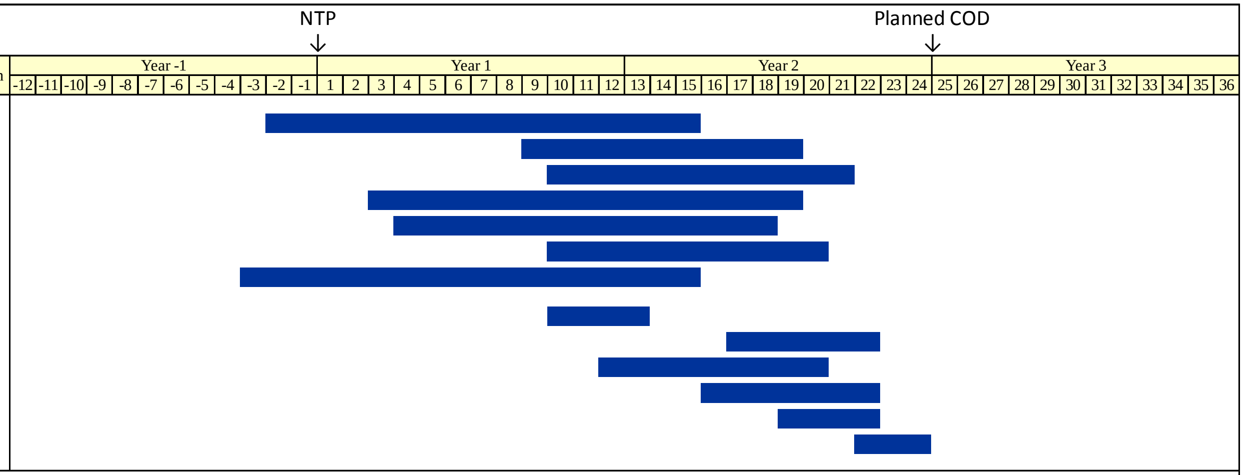
Notes:

1. Net plant output and O&M cost estimates were based on hot-day performance.
2. Based on use of GE parts, with the exception of the RICE.
3. Costs are annual average values.

4.5 PRELIMINARY PROJECT SCHEDULE

Preliminary project schedules for the SCCT and RICE technologies are summarized on Figure 4-2 through Figure 4-5. The estimated project durations are 27 months for the 1x0 LMS100PA, 22 months for the 1x0 GE LM6000, 24 months for the 1x0 GE 7F 5-Series, and 26 months for the 6x0 Wartsila 18V50SG power plant. The estimated project durations are current as of 2013. As with capital costs, project durations are affected by current market conditions and are subject to change.

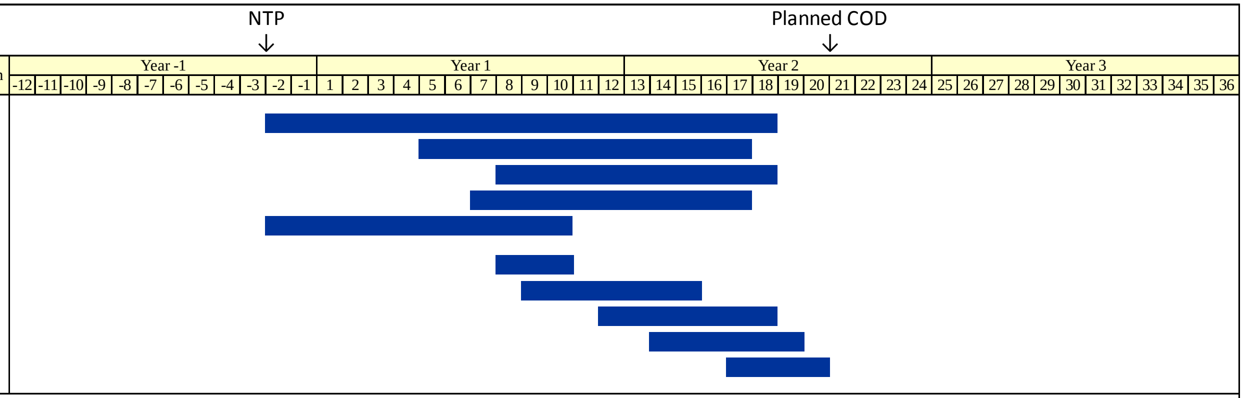
1x0 GE LMS100 PA	Start	Complete	Duration
GSU & Unit Aux Transformers	-2	15	17
Electrical Equipment	9	19	11
CEMS	10	21	12
Heat Exchanger	3	19	17
Intercooler	4	18	15
Stack	10	20	11
CT	-3	15	18
Site Preparation	10	13	4
CT Erection	17	22	6
Substructures	12	20	9
Cooling	16	22	7
BOP Mech/Elec Construction	19	22	4
Commissioning	22	24	3



Notes:
1. Schedule assumes permitting is complete at the start of construction.
2. Typical natural gas plant permitting lasts 14 to 18 months.
3. Site preparation may vary from 3 to 10 months, depending on whether "green" or "pre-developed" site, water table, existing facilities, etc.
4. Specific durations may need to be adjusted depending on where the calendar months fit vs. ordinal months due to weather concerns.
5. This schedule is based on current market conditions and is subject to change.

Figure 4-2 1x0 GE LMS100PA SCCT Preliminary Project Schedule

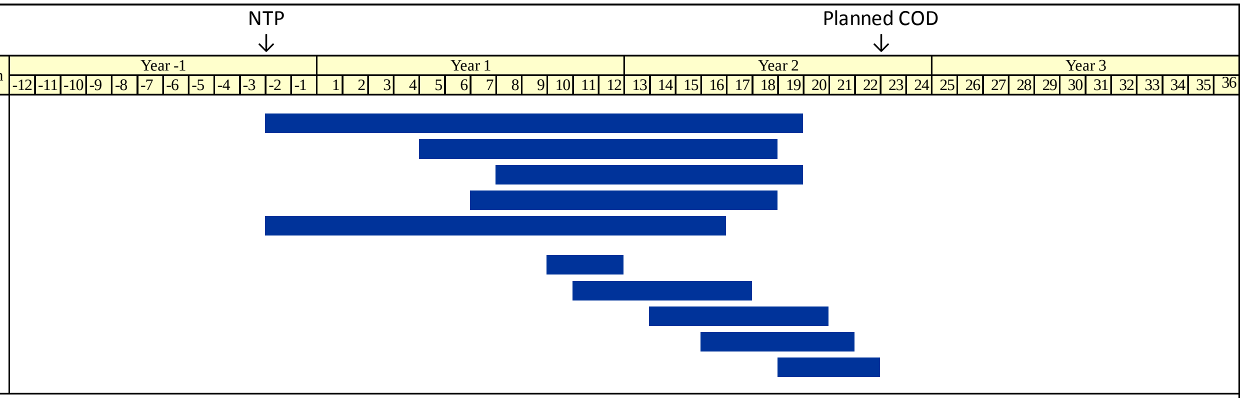
1x0 GE LM6000 PH	Start	Complete	Duration
GSU & Unit Aux Transformers	-2	18	20
Electrical Equipment	5	17	13
CEMS	8	18	11
Stack	7	17	11
CT	-2	10	12
Site Preparation	8	10	3
Substructures	9	15	7
CT Erection	12	18	7
BOP Mech/Elec Construction	14	19	6
Commissioning	17	20	4



Notes:
1. Schedule assumes permitting is complete at the start of construction.
2. Typical natural gas plant permitting lasts 14 to 18 months.
3. Site preparation may vary from 3 to 10 months, depending on whether "green" or "pre-developed" site, water table, existing facilities, etc.
4. Specific durations may need to be adjusted depending on where the calendar months fit vs. ordinal months due to weather concerns.
5. This schedule is based on current market conditions and is subject to change.

Figure 4-3 1x0 GE LM6000PH SCCT Preliminary Project Schedule

1x0 GE 7F 5-Series	Start	Complete	Duration
GSU & Unit Aux Transformers	-2	19	21
Electrical Equipment	5	18	14
CEMS	8	19	12
Stack	7	18	12
CT	-2	16	18
Site Preparation	10	12	3
Substructures	11	17	7
CT Erection	14	20	7
BOP Mech/Elec Construction	16	21	6
Commissioning	19	22	4



Notes:
1. Schedule assumes permitting is complete at the start of construction.
2. Typical natural gas plant permitting lasts 14 to 18 months.
3. Site preparation may vary from 3 to 10 months, depending on whether "green" or "pre-developed" site, water table, existing facilities, etc.
4. Specific durations may need to be adjusted depending on where the calendar months fit vs. ordinal months due to weather concerns.
5. This schedule is based on current market conditions and is subject to change.

Figure 4-4 1x0 GE 7F 5-Series SCCT Preliminary Project Schedule

NTP (at month -2) — Planned COD (at month 24)

Year -1: months -12 to -1; Year 1: months 1 to 12; Year 2: months 13 to 24; Year 3: months 25 to 36

6x0 Wartsila 18V50SG	Start	Complete	Duration
GSU & Unit Aux Transformers	-2	19	21
Electrical Equipment	5	18	14
CEMS	8	19	12
Stack	7	18	12
CT	-2	11	13
Site Preparation	10	14	5
Substructures	11	19	9
CT Erection	14	22	9
BOP Mech/Elec Construction	16	23	8
Commissioning	19	22	6

Notes:
1. Schedule assumes permitting is complete at the start of construction.
2. Typical natural gas plant permitting lasts 14 to 18 months.
3. Site preparation may vary from 3 to 10 months, depending on whether "green" or "pre-developed" site, water table, existing facilities, etc.
4. Specific durations may need to be adjusted depending on where the calendar months fit vs. ordinal months due to weather concerns.
5. This schedule is based on current market conditions and is subject to change.

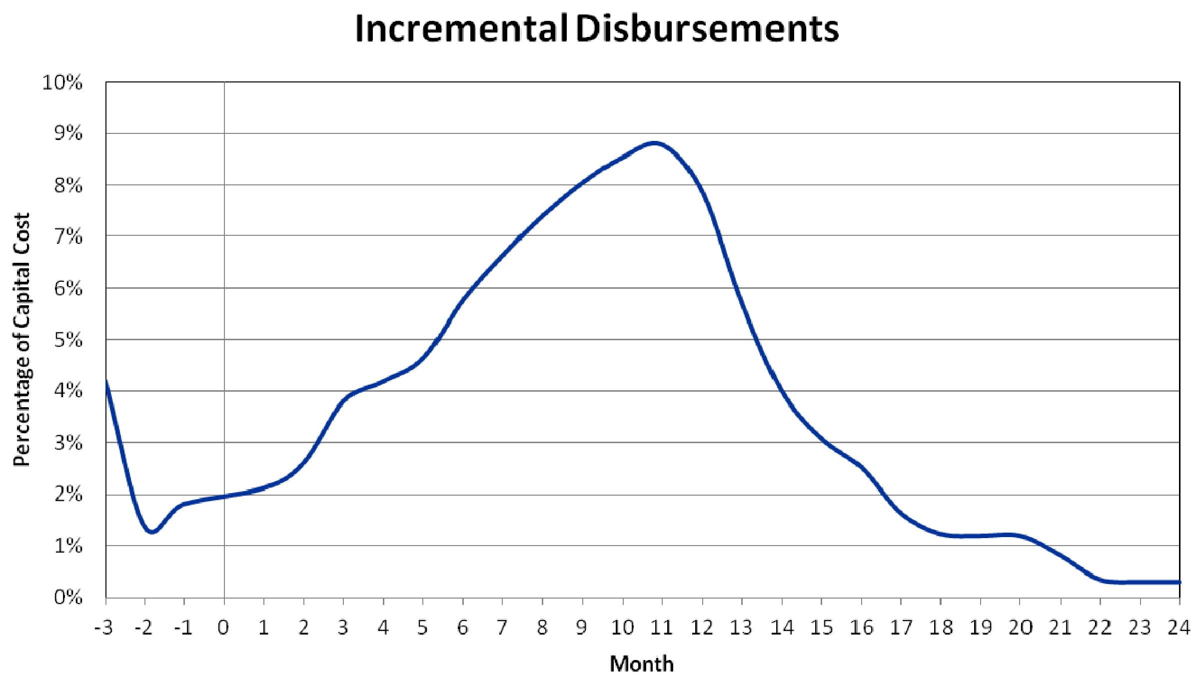
Figure 4-5 6x0 Wartsila 18V50SG RICE Preliminary Project Schedule

4.6 PRELIMINARY CASH FLOW

Preliminary cash flow summaries of the SCCT and RICE technologies are provided in Table 4-11 and depicted graphically on Figure 4-6 through Figure 4-9. The estimates include incremental and cumulative cash flows and are shown as a percentage of total capital cost versus time. The cash flow summaries were based on the preliminary project schedules described in the previous section.

Table 4-11 Preliminary SCCT and RICE Cash Flow Estimates

MONTH	1x0 GE LMS100PA		1x0 GE LM6000PH		1x0 GE 7F 5-SERIES		6x0 WARTSILA 18V50SG	
	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative
-3	4.2	4.2	--	--	--	--	--	--
-2	1.4	5.6	4.2	4.2	4.3	4.3	4.2	4.2
-1	1.8	7.4	2.4	6.6	1.7	6.0	1.5	5.7
1	2.1	9.5	2.5	9.0	2.0	8.0	1.9	7.6
2	2.6	12.1	3.2	12.3	2.7	10.7	2.2	9.8
3	3.8	15.9	4.5	16.8	3.7	14.3	3.0	12.8
4	4.2	20.1	5.3	22.1	4.7	19.0	4.0	16.8
5	4.6	24.7	6.4	28.5	5.0	24.0	4.4	21.2
6	5.8	30.5	7.7	36.2	6.3	30.3	5.2	26.4
7	6.6	37.1	8.8	45.0	7.7	38.0	6.3	32.7
8	7.4	44.5	10.0	55.0	8.3	46.3	7.2	39.8
9	8.0	52.6	10.5	65.5	9.3	55.7	8.0	47.8
10	8.5	61.1	10.1	75.6	9.8	65.5	8.5	56.4
11	8.8	69.9	8.2	83.8	9.7	75.2	9.1	65.5
12	7.9	77.7	4.5	88.3	7.3	82.5	9.0	74.5
13	5.7	83.5	3.4	91.7	4.5	87.0	7.0	81.5
14	4.0	87.4	2.4	94.1	3.7	90.7	4.6	86.1
15	3.1	90.5	1.7	95.8	2.7	93.3	3.5	89.5
16	2.5	93.0	1.4	97.2	1.7	95.0	2.8	92.3
17	1.6	94.7	1.3	98.5	1.3	96.3	2.0	94.3
18	1.2	95.9	0.8	99.3	1.3	97.7	1.3	95.6
19	1.2	97.1	0.4	99.6	1.3	99.0	1.2	96.8
20	1.2	98.3	0.4	100.0	0.3	99.3	1.2	98.1
21	0.8	99.1	--	--	0.3	99.7	0.9	99.0
22	0.3	99.4	--	--	0.3	100.0	0.4	99.4
23	0.3	99.7	--	--	--	--	0.3	99.7
24	0.3	100.0	--	--	--	--	0.3	100.0



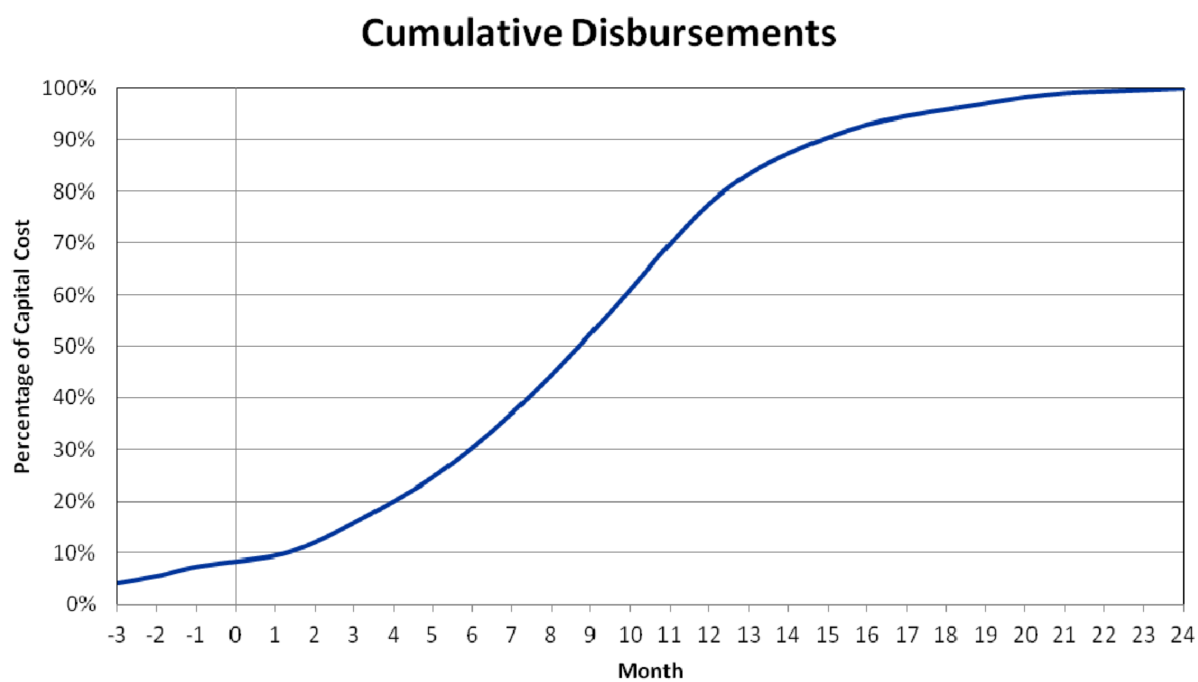


Figure 4-6 1x0 GE LMS100PA SCCT Cash Flow Curves

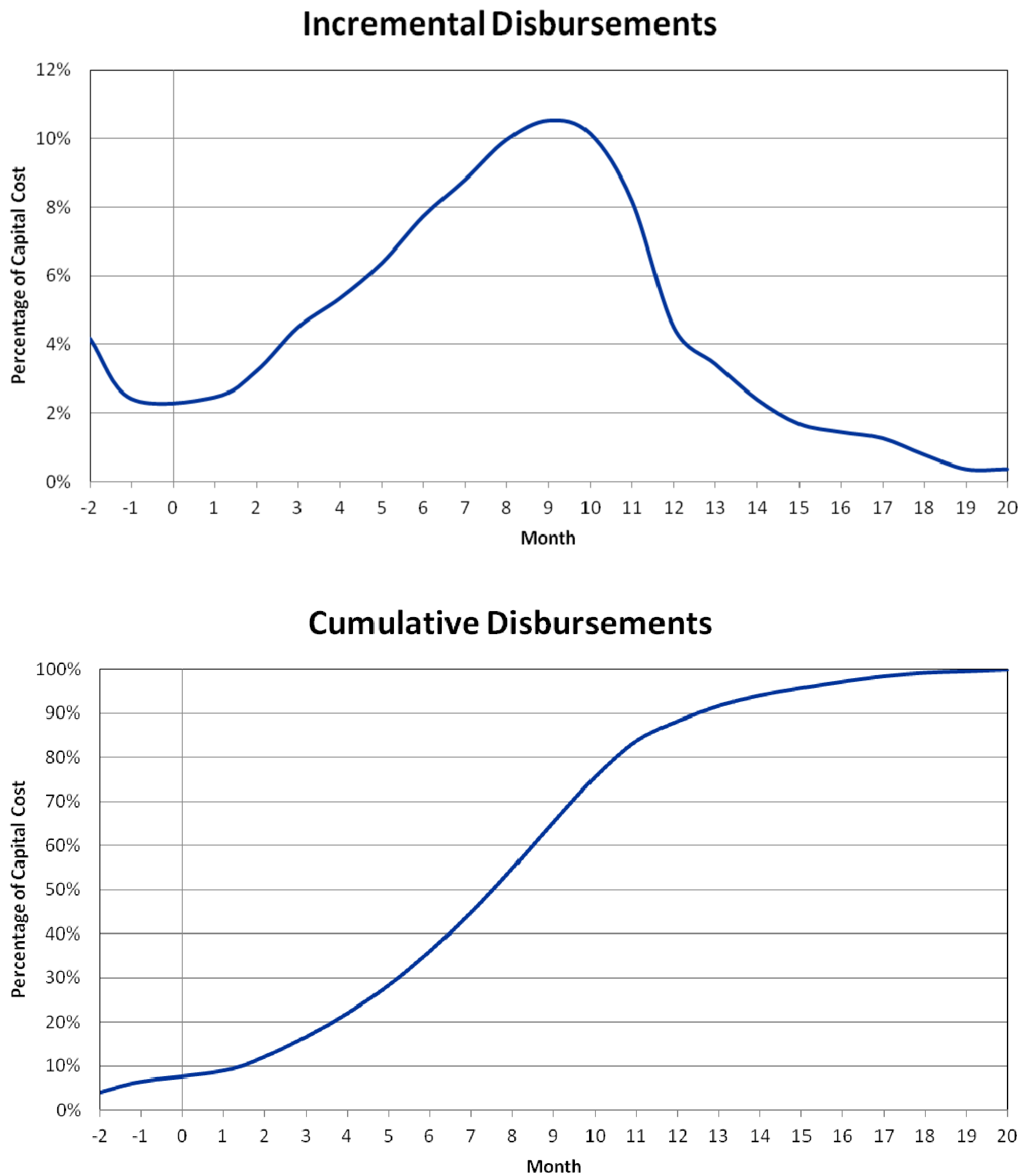
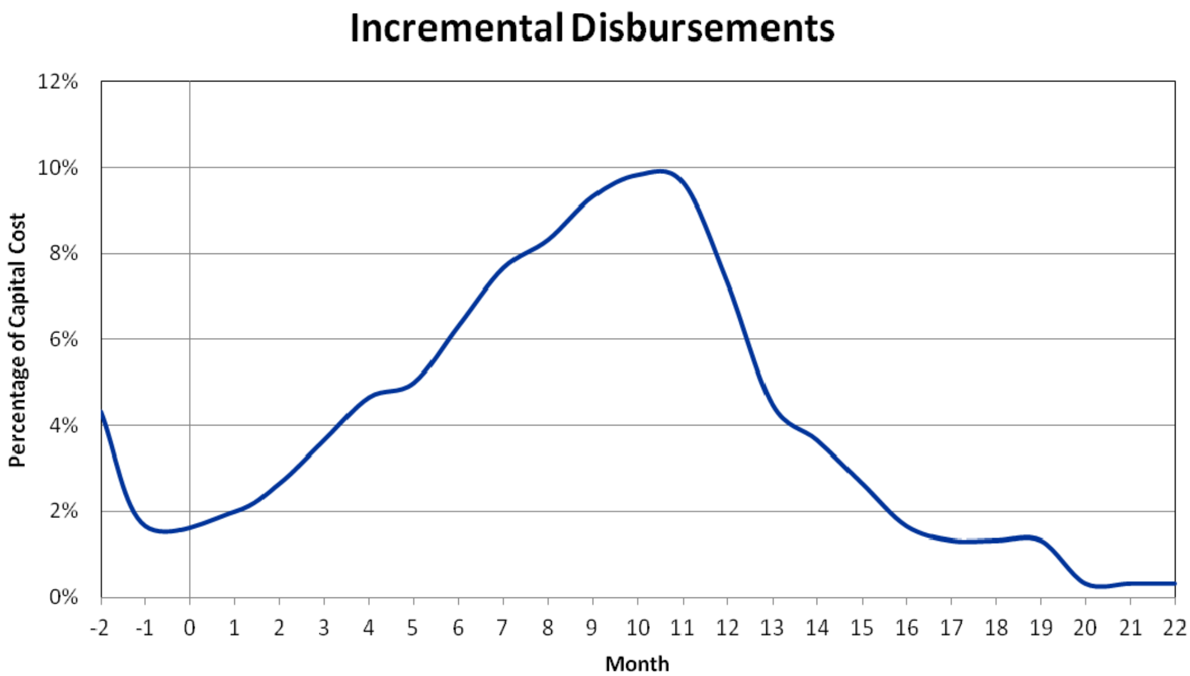


Figure 4-7 1x0 GE LM6000PH SCCT Cash Flow Curves



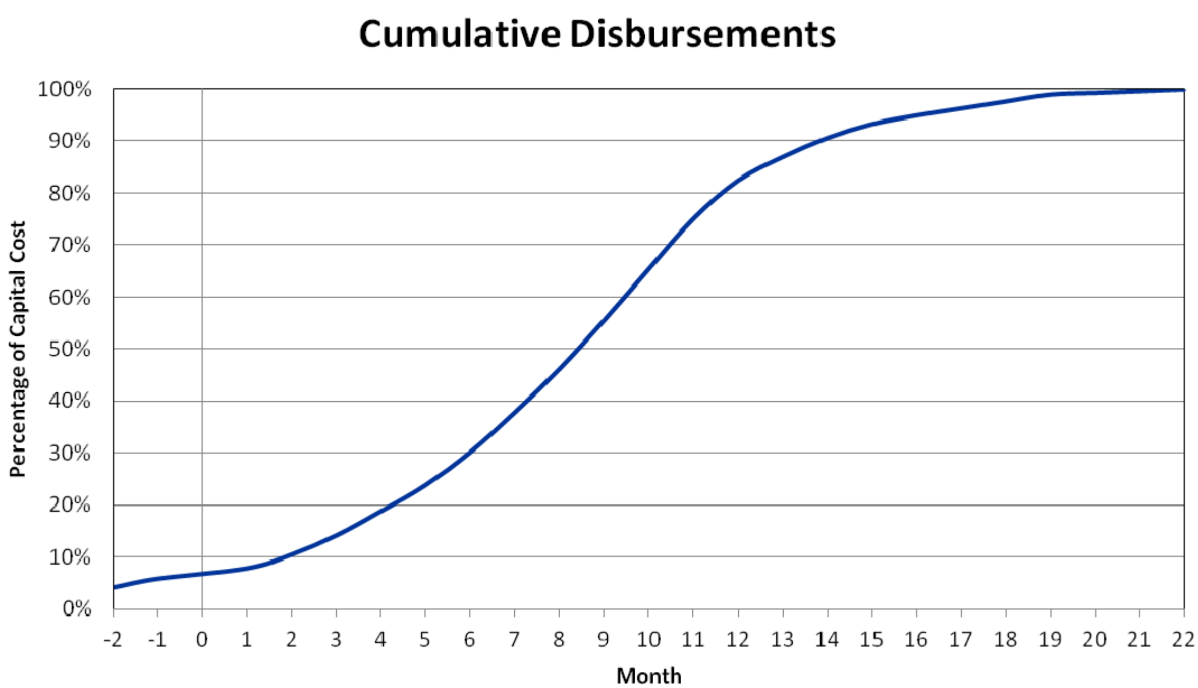
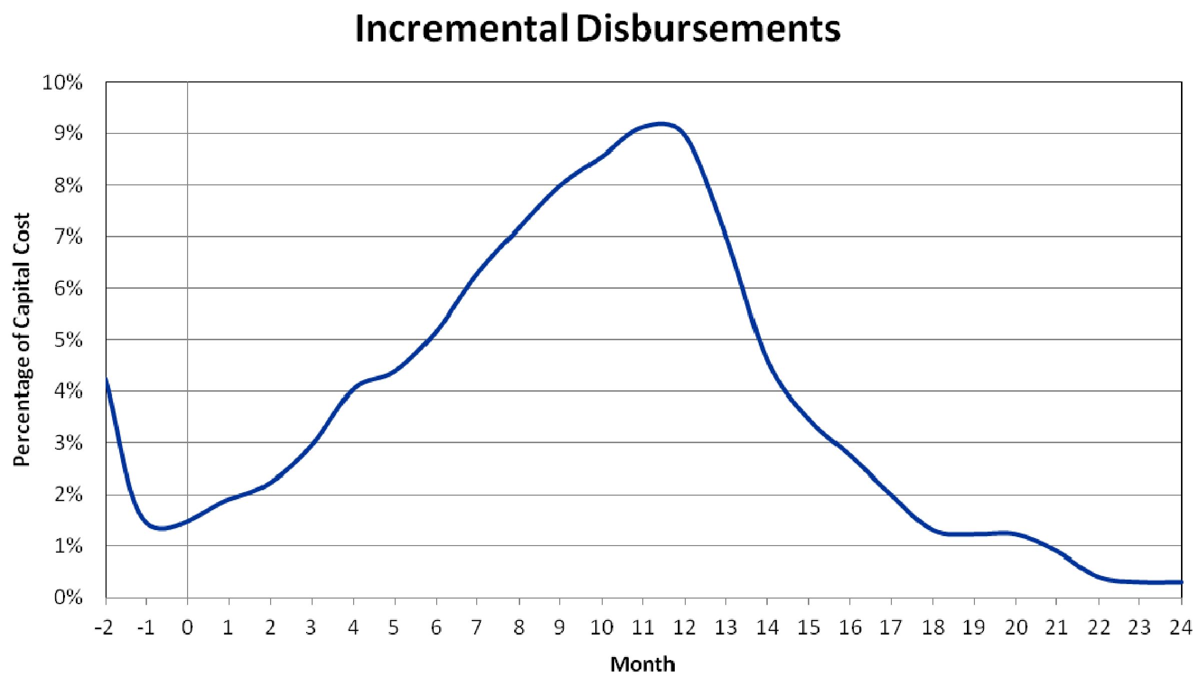


Figure 4-8 1x0 GE 7F 5-Series SCCT Cash Flow Curve



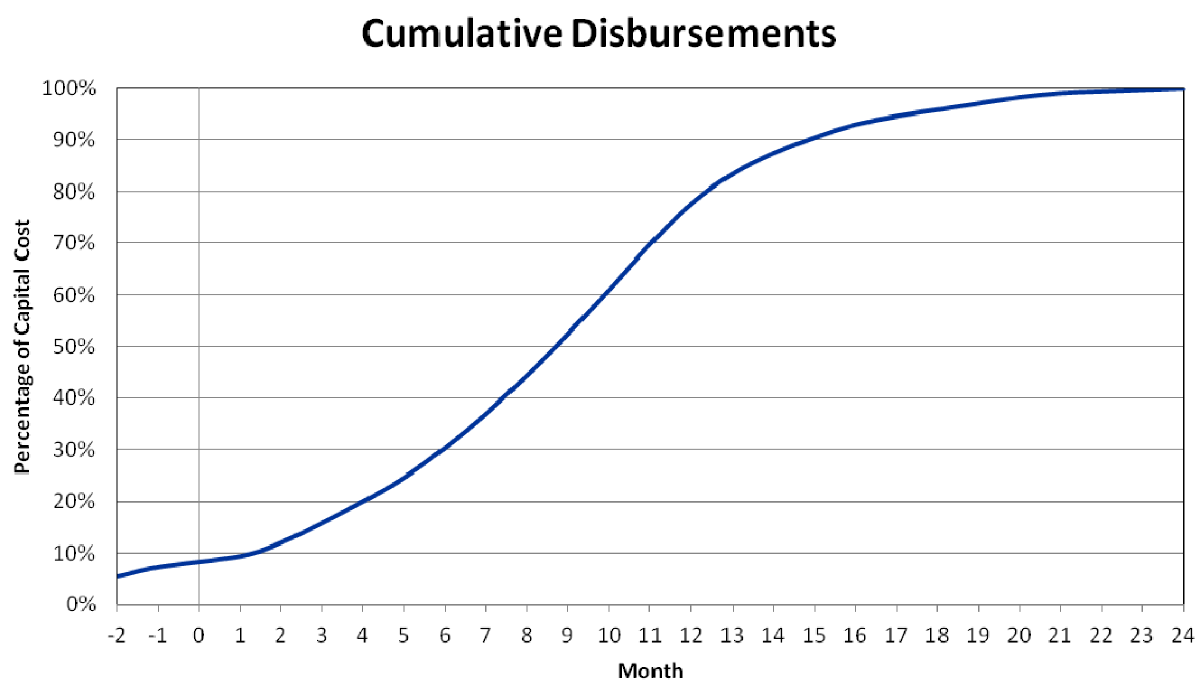


Figure 4-9 6x0 Wartsila 18V50SG SCCT Cash Flow Curve

5.0 Combined Cycle Combustion Turbine Options

This section includes technology descriptions, performance and emissions, and cost characteristics for the following CCCT technology options:

- 1x1 GE 7F 5-Series.
- 2x1 GE 7F 5-Series.

The following characteristics are addressed for each option:

- Summary level technology descriptions.
- Thermal performance estimates including net plant output and net plant heat rate.
- AQCS assumptions based on probable BACT emission requirements.
- The following cost estimates are provided in 2013$:
  - Order of magnitude overnight EPC capital cost estimates.
  - Fixed and non-fuel variable O&M.
- Typical high-level outage maintenance schedule.
- Preliminary project schedule and project durations.
- Preliminary cash flow summary.

5.1 TECHNOLOGY DESCRIPTIONS

The following subsections provide an overview of the CCCT arrangement and process flow as well as discussions specific to the GE 7F 5-Series CCCT plant. Additional descriptions generic to CTGs are provided in Section 4.1.

5.1.1 CCCT Operational Description

The major components of a CCCT unit include the CTG(s), heat recovery steam generator (HRSG), steam turbine generator (STG), heat rejection, and AQCS. In a CCCT unit, an HRSG is used to recover the thermal energy of the hot CTG exhaust gases to generate high energy steam. High energy steam is produced when hot exhaust gas from the CTG(s) is passed through the HRSG and over the heat transfer surface areas of the HRSG. Steam produced in the HRSG is utilized in a Rankine cycle by expanding it through the STG coupled to an electric generator. Thermal energy converted to kinetic energy by the steam turbine is used to drive an electric generator to produce additional electric power.

The overall efficiency of a combined cycle configuration is greater than that of a simple cycle configuration, which utilizes just a CTG. In a combined cycle, 45 to 60 percent of the fuel energy can be converted to electrical energy as opposed to 35 to 40 percent in a simple cycle. Newer F- and H-class heavy-duty combustion turbine (HDCT) designs have the capability of around 60 percent net plant efficiency.

Combined cycle units can be arranged with single or multiple CTGs. In a 1x1 arrangement, one CTG would supply hot combustion gas to a single HRSG. Steam produced in the HRSG would supply steam at the design pressure and temperature to a single STG. In a multiple CTG arrangement, two or more CTGs would each supply hot combustion gas to a dedicated HRSG. Steam produced in the HRSG would then be collected and expanded through a single STG. Combined cycle units are commonly installed in a 1x1 (one CTG and HRSG, and STG) or 2x1 (two CTGs and HRSGs, and one common STG) arrangement. The HRSG can be supplementally (or duct) fired to produce additional steam for added plant output. Schematic diagrams showing typical 1x1 and 2x1 arrangements for a CCCT plant are provided on Figure 5-1 and Figure 5-2.

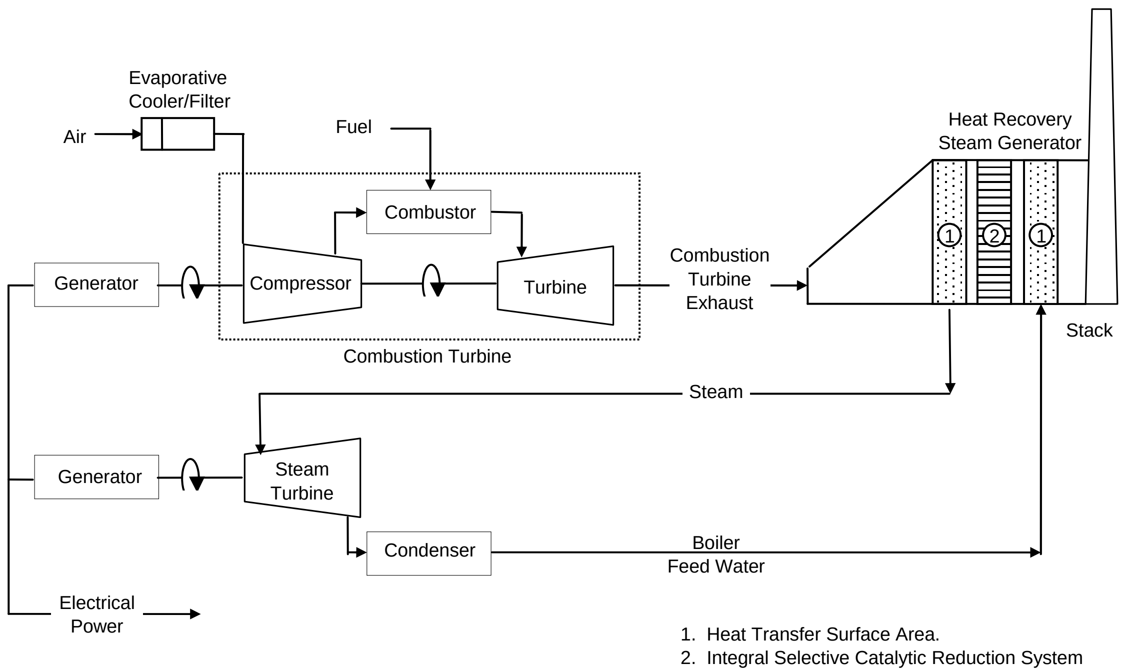


Figure 5-1 1x1 CCCT Power Plant Schematic Diagram

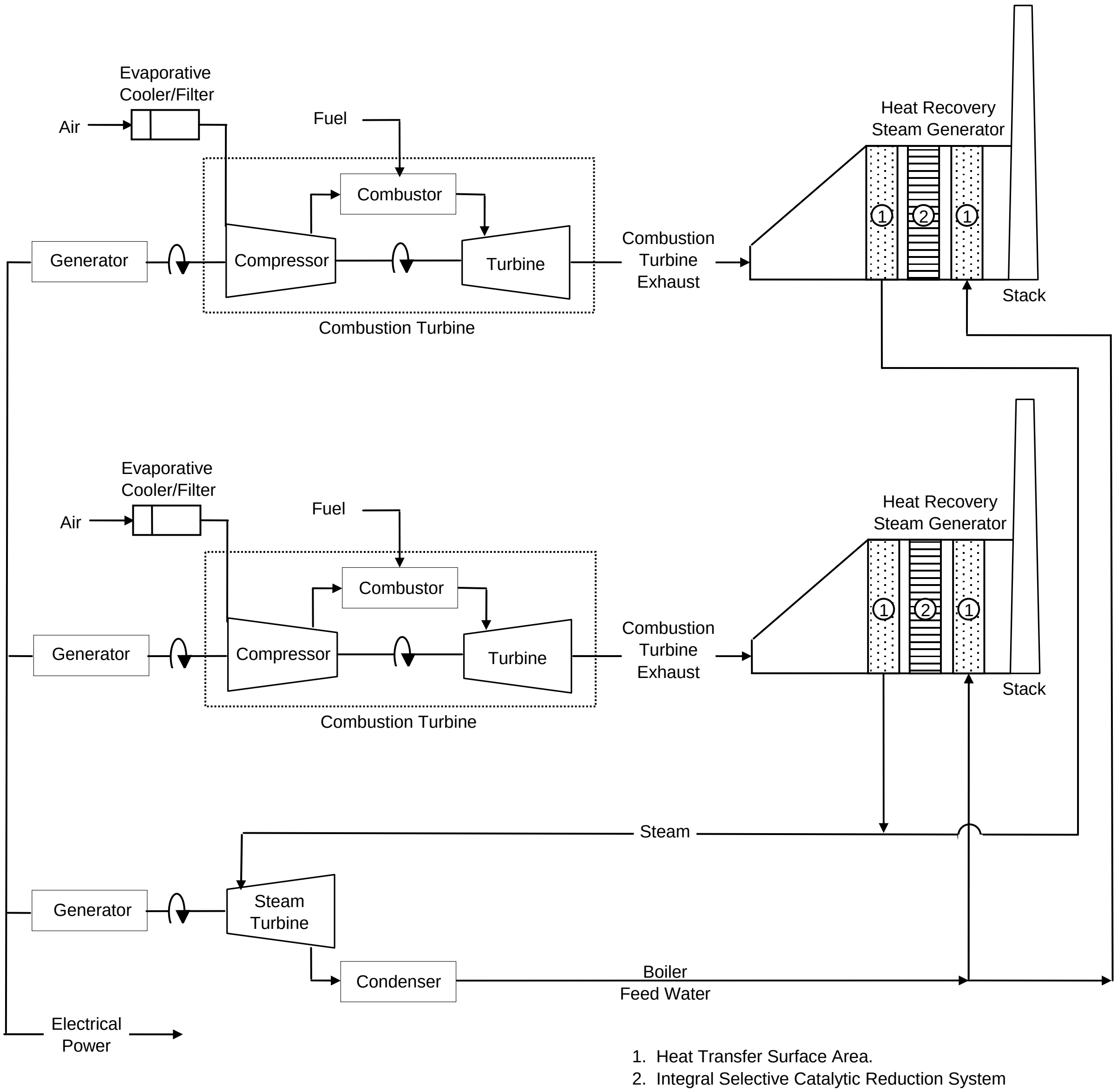


Figure 5-2 2x1 CCCT Power Plant Schematic Diagram

5.1.2 GE 7F 5-Series CCCT

In 2009, GE began offering model updates to the GE 7FA (7241), with the GE 7F 5-Series CTG available for shipment in 2011. The updates include performance enhancements that has resulted in CTG efficiency improvements and an up-rate in output that has increased the ISO output of the past 7FA (7241) in a 2x1 CCCT configuration from 530 MW to 655 MW.

Additional descriptions regarding the GE 7F 5-Series CTG are provided in Subsection 4.1.4. Table 5-1 provides ISO performance characteristics from the 2013 GTW Handbook for the 7F 5-Series in 1x1 and 2x1 CCCT configurations. It should be noted that the performance data shown in the 2013 GTW handbook is for net output, based on ISO conditions, at the generator terminals, while firing natural gas, with unfired, multi-pressure, reheat HRSGs, without SCR or CO catalysts, using a wet mechanical draft cooling tower, exclusive of BOP auxiliary loads. Refer to the referenced document for more information.

Table 5-1 GE 7F 5-Series 1x1 and 2x1 CCCT Characteristics (GTW-ISO)

MODEL	NET PLANT OUTPUT, MW	NET PLANT HEAT RATE HHV (LHV), BTU/KWH	PERCENT (%)
1x1 GE 7F 5-Series	323	6,508 (5,863)	52.4 (58.2)
2x1 GE 7F 5-Series	655	6,419 (5,783)	53.2 (59.0)
Note: Net plant output and net plant heat rate values shown assume a 1.0 percent parasitic power consumption requirement to operate the plant.			

5.2 PERFORMANCE AND EMISSIONS

This section presents estimates of thermal performance and emissions for the CCCT technologies. For the purpose of the evaluation, the technologies were evaluated on a consistent basis relative to one another. Arrangement assumptions specific to each CCCT case, which were used in the development of the estimates, are summarized in Table 5-2.

The performance estimates include net plant outputs and net plant heat rates when firing natural gas; these are summarized in Table 5-3. Performance estimates were generated on the basis of hot-day and cool-day ambient temperatures, as defined in Section 2.1. Hot-day full load performance includes the effects of inlet evaporative cooling. Hot-day full load performance also includes the effects of duct firing the HRSG to recover the STG turbine output to the cool-day STG output. For the estimates, the STG was sized according to the cool-day CTG and HRSG performance.

Full-load air emissions estimates for the CCCT technologies are summarized in

Table 5-4 for hot-day ambient temperatures. The air emissions data include NO_x, SO_2, CO, CO_2, and particulate matter. The emissions rates in the table are expressed in lb/MBtu of heat input to the CTGs.

The performance and emissions estimates are for new and clean units and do not include the effects of degradation. The emissions estimates were based on the assumed AQCS, which is reflective of current BACT requirements. Specific AQCS were selected as the design basis for the purpose of developing performance and cost estimates; these are summarized in Table 5-2.

Table 5-2 CCCT Cycle Arrangement Assumptions

COMBUSTION TURBINE	GE 7F 5-SERIES	GE 7F 5-SERIES
Arrangement	1x1	2x1
Number of Combustion Turbines	1	2
Steam Turbine	Subcritical	Subcritical
Number of Steam Turbines	1	1
Reheat Cycle	Yes	Yes
Duct Firing Capability	Yes	Yes
Combustion Turbine Inlet Cooling	Evaporative	Evaporative
Main Steam Temperature, ° F	1,050	1,050
HRSG Pressure/Steam Drum Count	3	3
Rankine Cycle Heat Rejection	Wet Mechanical Draft Cooling Tower	Wet Mechanical Draft Cooling Tower
Boiler Feed Pump Drive	Electric Motor	Electric Motor
Fuel	Natural Gas	Natural Gas
NO_x Combustion Control	DLE	DLE
NO_x Post-Combustion Control	SCR	SCR
CO Post-Combustion Control	CO Catalyst	CO Catalyst

Table 5-3 CCCT Thermal Performance Estimates

	AMBIENT TEMP.	CTG LOAD LEVEL	NET PLANT OUTPUT, KW	NET PLANT HEAT RATE (HHV), BTU/KWH	NET PLANT HEAT RATE (LHV), BTU/KWH
1x1 GE 7F 5-Series	20° F	Full	335,100	6,660	6,000
		75%	260,000	6,810	6,140
		52%	192,700	7,350	6,620
	95° F	Full(1)	299,800	6,700	6,040
		75%	224,300	6,940	6,250
		52%	173,300	7,550	6,800
2x1 GE 7F 5-Series	20° F	Full	675,800	6,600	5,950
		2 CTGs at 75%	524,700	6,750	6,080
		2 CTGs at 52%	390,000	7,260	6,540
		1 CTG at 100%	334,400	6,670	6,010
		1 CTG at 52%	187,900	7,530	6,780
	95° F	Full(1)	604,700	6,640	5,980
		2 CTGs at 75%	452,500	6,870	6,190
		2 CTGs at 52%	350,000	7,470	6,730
		1 CTG at 100%	288,100	6,760	6,090
		1 CTG at 52%	166,200	7,870	7,090

Notes:

1. For hot-day, full load conditions, the HRSGs have been partially duct fired to reach the cool-day STG output. The STG was sized based on cool-day CTG and HRSG performance.
1. CTG performance was based on an elevation of 1,000 feet and 60 percent relative humidity.
2. All performance was based on 100 percent methane with 0.2 grain of sulfur per 100 scf.
3. Cycle performance is highly dependent on the specific plant design parameters (e.g., fuel constituents, site ambient conditions, and throttle conditions). The actual plant heat rates may vary by as much as 10 percent from the heat rates shown above.
4. Net output and heat rate were based on an assumed auxiliary load of 2.5% x full load, or for off-design, 1.25% x full load + 1.25% x reduced load.
5. All data are expected and are not guaranteed; they do not include allowances for margins.

Table 5-4 CCCT Emissions Estimates

	CT LOAD LEVEL	NO_X, AS NO_2		SO_2		CO	CO_2	PM_{10}
		ppm	lb/MBtu	ppm	lb/MBtu	lb/MBtu	lb/MBtu	lb/MBtu
1x1 GE 7F 5-Series	Full	2.5	0.01	4.0	0.0004	0.01	128	0.01
2x1 GE 7F 5-Series	Full	2.5	0.01	4.0	0.0005	0.01	128	0.01

Notes:
2. For hot-day, full load conditions, the HRSGs have been partially duct fired to reach the cool-day STG output. The STG was sized based on cool-day CTG and HRSG performance.
3. Emissions estimates are representative of hot-day, full load conditions. Evaporative coolers are assumed to be in operation for the hot-day, full load cases.
4. ppm is parts per million dry volume at 15 percent O_2.
5. All performance was based on 100 percent methane with 0.2 grains of sulfur per 100 scf. It is assumed there are no Hg or Pb emissions for burning natural gas.
6. CCCT emissions data shown include SCR and CO catalyst.
7. PM_{10} emissions shown are front and back half catch and include SO_2 to SO_3 oxidation.
8. All data are expected and are not guaranteed; they do not include allowances for margins.

5.3 CAPITAL COSTS

Market-based, order of magnitude overnight EPC capital and total project cost estimates were generated for each of the CCCT technologies; these are provided in Table 5-5. An EPC cost basis, exclusive of Owner's costs, was utilized. Typically, the scope of work for an EPC cost is the base plant, which is defined as being "within the fence" with distinct boundaries and terminal points. A total project cost estimate is defined as the EPC capital cost plus an Owner's Cost Allowance. The Owner's Cost Allowance was assumed as a percentage of the EPC capital cost.

The estimates were based on Black & Veatch proprietary estimating templates and experience. The order of magnitude estimates were prepared for the purposes of project screening, resource planning, comparison of alternative technologies, etc., and as such, are expected to be in the range of ±30 percent of actual project costs. The cost estimates were calculated using a consistent methodology between technologies, so although the absolute cost estimates are expected to vary within a band of accuracy, the relative accuracy between technologies is better. The information is consistent with recent experience and market conditions, but as demonstrated in recent years, the market is dynamic and unpredictable. Power plant costs will be subject to continued volatility in the future, and the estimates in this report should be considered primarily for comparative purposes.

The following listing provides general EPC capital cost estimating assumptions. The general assumptions identify the scope of supply included in the EPC capital cost estimate. Assumptions related to the development of the performance estimates also apply to the EPC cost estimates. Assumptions related to direct and indirect costs and Owner's costs were provided in Section 2.0. Overall site assumptions were also provided in Section 2.0.

1. Cost estimates are provided for each of the following technologies:
   a. 1x1 GE 7F 5-Series CCCT.
   b. 2x1 GE 7F 5-Series CCCT.
2. The plant will feature CTG(s), HRSG(s), and one condensing STG. The primary fuel will be natural gas. No consideration was given to possible future expansion of the facilities.
3. The CTG(s) includes a standard enclosure. A bridge crane for servicing the CTG(s) is included.
4. The three pressure, reheat HRSG(s) includes duct firing and stack damper.
5. Bypass dampers and stacks are not included.
6. An SCR and CO oxidation catalyst is included for NO_x and CO control.
7. Pilings are included under major equipment. Spread footings were assumed for all other foundations. Further stabilization of the existing subgrade is not included.
8. Major buildings included in the costs estimate are as follows:
   a. A central control/electrical building is included for the site; it would be sized to enclose a control room, battery room, motor control center, meal room and toilets, locker room, and various offices.

   b. The estimate includes an administration/workshop/warehouse building, which will provide administration offices, storage and workshop areas, instrument shop, a locker room, and a drawing room.
   c. A water treatment building is included that would be sufficient for the enclosure of the water treatment equipment and fire water pumps.
   d. All buildings will be pre-engineered metal structures.
9. Onsite water treatment includes the following:
   a. Pretreatment system for plant water.
   b. Reverse osmosis and mixed bed demineralization systems for cycle makeup water.
10. A sanitary waste treatment system is included.
11. Construction power and water are assumed to be available within the site boundary.
12. The supply of natural gas will be available at the site boundary at the appropriate conditions that meet the CTG vendor requirements. No. 2 fuel oil will be delivered by truck to a fuel oil storage tank sized for five full-load days' unit operation.
13. Automatic fire protection will consist of the CTG OEM-supplied standard CO_2 fire suppression system, water deluge of the transformers, dry pipe fire protection of the cooling tower, and wet pipe sprinkler system in the buildings (except in the control room, which will have fire detection equipment only and hydrant protection for the site).
14. A wet mechanical draft cooling tower will provide Rankine cycle heat rejection.
15. Field erected tanks will consist of the following:
   a. Demineralized water storage tank.
   b. Condensate storage tank.
   c. Raw water/fire water storage tank.
16. An emergency diesel generator for safe shutdown is included.

Table 5-5 CCCT EPC Capital Cost Estimates, 2013$

DESCRIPTION	1x1 GE 7F 5-SERIES	2x1 GE 7F 5-SERIES
Total Direct Costs, $1000	225,840	369,000
Total Indirect Costs, $1000	81,360	126,600
Estimated EPC Cost, $1,000	307,200	495,600
Net Plant Output, kW (1)	299,800	604,700
EPC Unit Cost, $/kW	**1,025**	**820**
Owner's Cost Allowance, percentage of EPC Cost	35	35
Owner's Cost Allowance, $1,000	107,500	173,500
Total Project Cost, $1,000	414,700	669,100
Total Project Unit Cost, $/kW	**1,383**	**1,106**

Notes:
1. Based on the estimated thermal performance at hot-day ambient conditions and 100 percent load.
2. All EPC cost estimates are presented in 2013 dollars. The costs are order of magnitude estimates and, as such, they are expected be have an accuracy of ± 30 percent of the EPC cost.
3. EPC costs are exclusive of Owner's costs.
4. The sum of the EPC cost and the Owner's costs will equal the total project cost. Owner's Cost is assumed to be 35 percent of estimated turnkey EPC Cost.

5.4 O&M COSTS

Estimates of O&M expenses, including fixed and non-fuel variable average annual expenses, were developed for each of the CCCT technologies. O&M costs are provided in both total average annual costs and on a unitized basis. Unitized fixed costs, those costs that are independent of the energy generated by the plant, are provided on a $/kW-yr basis. Unitized variable costs, those costs that are dependent on the energy generated by the plant, are provided on a $/MWh basis. O&M costs were based on the assumed CF and the estimated thermal performance at hot-day ambient conditions at 100 percent load, with duct firing and evaporative cooler in service.

The O&M estimates were derived from order-of-magnitude estimates developed by Black & Veatch. Black & Veatch has utilized Alliant Energy's input in generating O&M cost assumptions as applicable. In the event that assumptions were not readily available from Alliant Energy, Black & Veatch provided assumptions that are reasonable for the project.

Assumptions specific to the development of the O&M cost estimates are provided in Table 5-6. Key O&M consumable costs were based on current market pricing. All assumptions relative to the development of the performance and capital cost estimates presented in previous sections were used in the development of the O&M cost estimates.

Estimates of O&M expenses for each of the CCCT options are provided in Table 5-7.

Table 5-6 CCCT O&M Operating Assumptions

	1x1 GE 7F 5-SERIES	2x1 GE 7F 5-SERIES
Key O&M Costs, 2013$		
Staff, count	17	22
Operator Base Salary, $/yr	76,000	76,000
Payroll Burden, percent	40	40
Operating Factors		
Capacity Factor, percent	45	45
Forced Outage Factor, percent	2.2	2.2
Availability Factor, percent	94	94
Service Factor, percent	45	45
Starts per Year, percent	200	200
Planned Outage Factor (Annualized), percent	2.0	2.0
Outage Maintenance		
CT Inspection Duration, days	7	7
CT Inspection Frequency, yrs/outage	2.25	2.25
CT HGP Inspection Duration, days	15	15
CT HGP Inspection Frequency, yrs/outage	4.5	4.5
CT Major Inspection Duration, days	30	30
CT Major Inspection Frequency, yrs/outage	9	9
Steam Turbine Outage Duration, days	30	30
Steam Turbine Outage Frequency, yrs/outage	9	9

Notes:
1. SCR is included for NO_x control on both CCCT options.
2. CO catalyst is included for CO control on both CCCT options.
3. CTG maintenance estimated costs were based on GE suggested maintenance and GE parts list pricing.
4. HRSG annual inspection costs were estimated on the basis of manufacturer input and Black & Veatch experience.
5. Net plant output and O&M cost estimates were based on hot-day performance, with the evaporative cooler and duct firing operational.

Table 5-7 CCCT Annual O&M Cost Estimates, 2013$

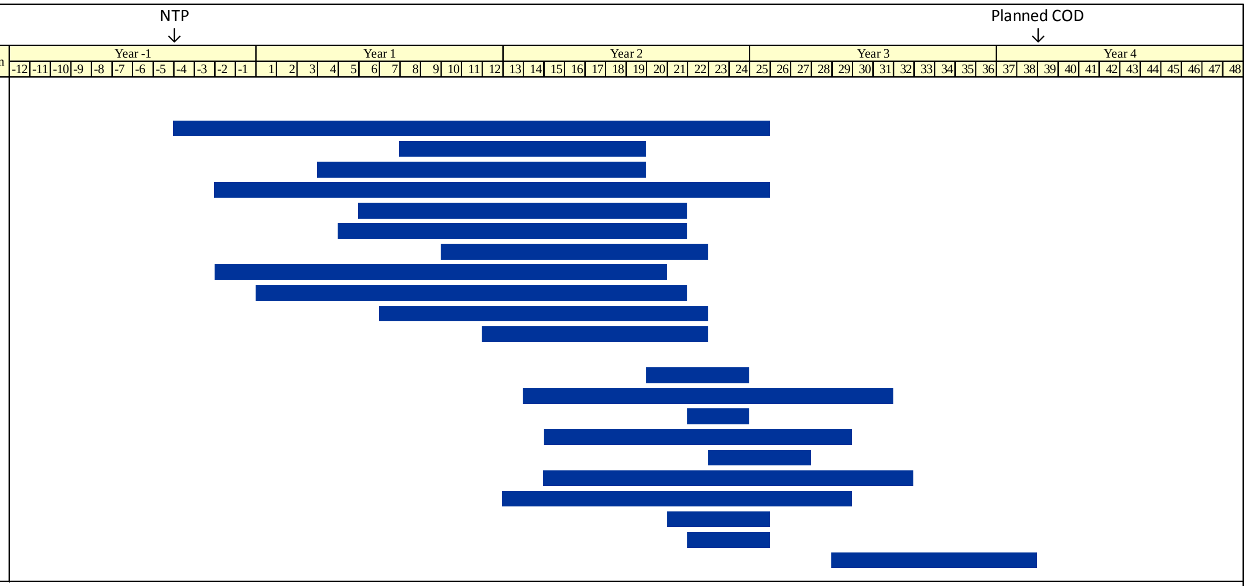
	1x1 GE 7F 5-SERIES	2x1 GE 7F 5-SERIES
Total Fixed Costs, $1,000	2,630	3,610
Total Nonfuel Variable Costs, $1,000	3,530	6,980
Net Plant Output, kW	299,800	604,700
Annual Net Generation, MWh	1,181,800	2,383,700
Fixed Costs, $/kW-yr	8.77	5.97
Variable Costs, $/MWh	2.99	2.93

Note:
1. Net plant output was based on the estimated thermal performance at hot-day ambient conditions and 100 percent load.
2. Expenses are on a levelized average annual basis.

5.5 PRELIMINARY PROJECT SCHEDULE

Preliminary project schedules for the CCCT technologies are summarized on Figure 5-3 and Figure 5-4. The estimated project duration is 42 months for both the 1x1 GE 7F 5-Series and the 2x1 GE 7F 5-Series CCCTs. The estimated project durations are current as of 2013. As with capital costs, project durations are affected by current market conditions and are subject to change.

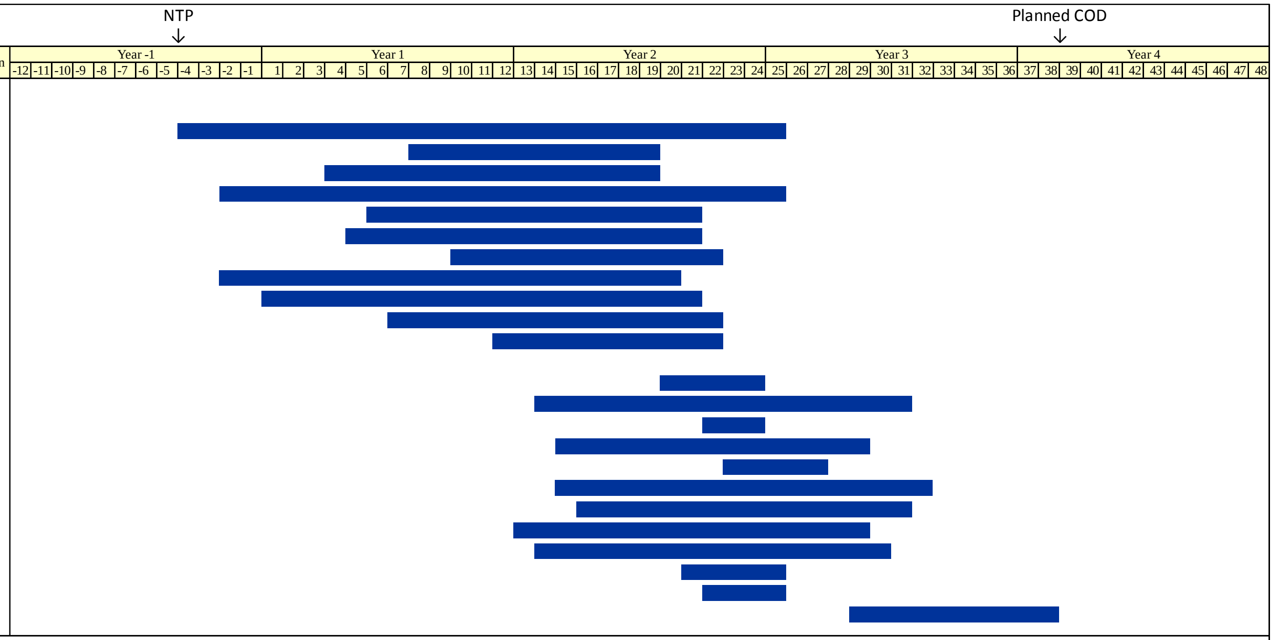
1x1 GE 7F 5-Series	Start	Complete	Duration
Engineering/Bid/Fab/Deliver			
Engineering Procurement	-4	25	29
Steel	8	19	12
Alloy Piping	4	19	16
Steam Turbine	-2	25	27
Condenser	6	21	16
Cooling Tower	5	21	17
Fuel Gas Equipment	10	22	13
CT	-2	20	22
HRSG	1	21	21
Water Treatment Equipment	7	22	16
Electrical Equipment	12	22	11
Site Construction			
Steel	20	24	5
Steam Turbine, Foundation Mat., Piping	14	31	18
Condenser	22	24	3
Cooling Tower, Basin, and Piping	15	29	15
Fuel Gas Equipment	23	27	5
CT, Foundation, and Piping	15	32	18
HRSG, Foundation, Steel, and Piping	13	29	17
Water Treatment Equipment	21	25	5
Electrical Equipment	22	25	4
Commissioning and Start-up	29	38	10



Notes:
1. Schedule assumes permitting is complete at the start of construction.
2. Typical natural gas plant permitting lasts 14 to 18 months.
3. Site preparation may vary from 3 to 10 months, depending on whether "green" or "pre-developed" site, water table, existing facilities, etc.
4. Specific durations may need to be adjusted depending on where the calendar months fit vs. ordinal months due to weather concerns.
5. This schedule is based on current market conditions and is subject to change.

Figure 5-3 1x1 GE 7F 5-Series CCCT Preliminary Project Schedule

2x1 GE 7F 5-Series	Start	Complete	Duration
Engineering/Bid/Fab/Deliver			
Engineering Procurement	-4	25	29
Steel	8	19	12
Alloy Piping	4	19	16
Steam Turbine	-2	25	27
Condenser	6	21	16
Cooling Tower	5	21	17
Fuel Gas Equipment	10	22	13
CT 1 and 2	-2	20	22
HRSG 1 and 2	1	21	21
Water Treatment Equipment	7	22	16
Electrical Equipment	12	22	11
Site Construction			
Steel	20	24	5
Steam Turbine, Foundation Mat., Piping	14	31	18
Condenser	22	24	3
Cooling Tower, Basin, and Piping	15	29	15
Fuel Gas Equipment	23	27	5
CT1, Foundation, and Piping	15	32	18
CT2, Foundation, and Piping	16	33	18
HRSG1, Foundation, Steel, and Piping	13	29	17
HRSG2, Foundation, Steel, and Piping	14	30	17
Water Treatment Equipment	21	25	5
Electrical Equipment	22	25	4
Commissioning and Start-up	29	38	10



Notes:
1. Schedule assumes permitting is complete at the start of construction.
2. Typical natural gas plant permitting lasts 14 to 18 months.
3. Site preparation may vary from 3 to 10 months, depending on whether "green" or "pre-developed" site, water table, existing facilities, etc.
4. Specific durations may need to be adjusted depending on where the calendar months fit vs. ordinal months due to weather concerns.
5. This schedule is based on current market conditions and is subject to change.

Figure 5-4 2x1 GE 7F 5-Series CCCT Preliminary Project Schedule

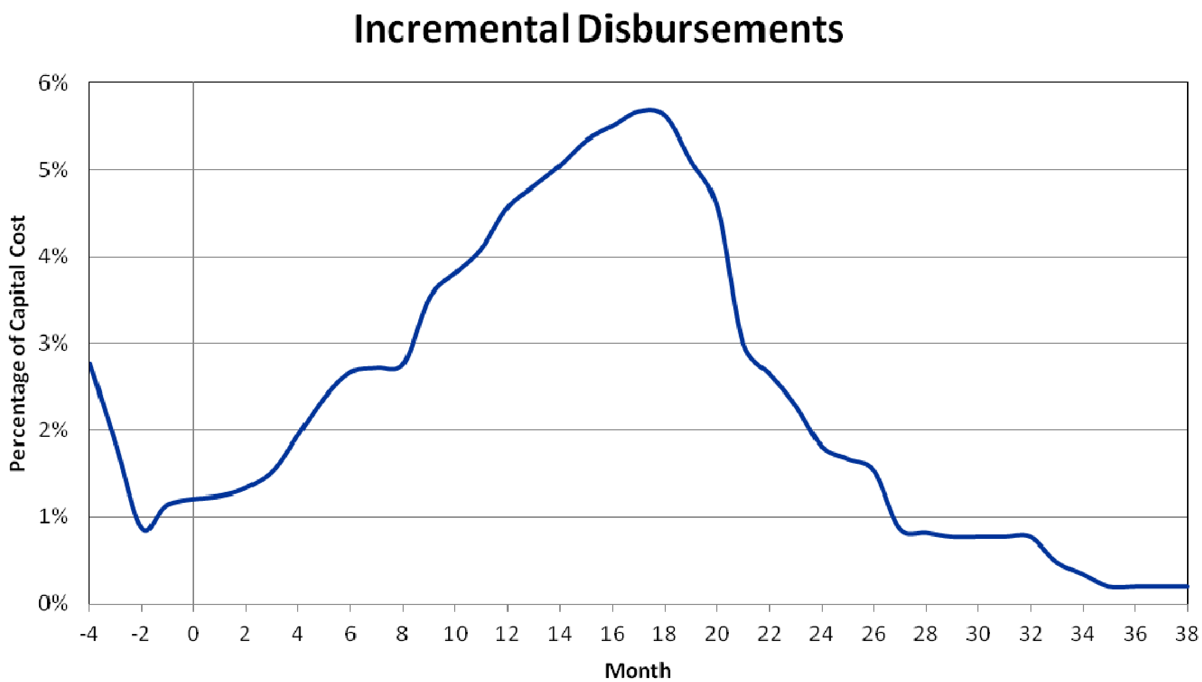
5.6 PRELIMINARY CASH FLOW

Preliminary cash flow summaries for the CCCT technologies are provided in Table 5-8 and depicted graphically on Figure 5-5 and Figure 5-6. The estimates include incremental and cumulative cash flows and are shown as a percentage of total capital cost versus time. The cash flow summaries were based on the preliminary project schedules described in the previous section.

Table 5-8 CCCT Cash Flow Estimates

MONTH	1x1 7F 5-SERIES		2x1 7F 5-SERIES	
	INCREMENTAL	CUMULATIVE	INCREMENTAL	CUMULATIVE
-4	2.8	2.8	2.8	2.8
-3	1.8	4.6	1.8	4.6
-2	0.9	5.4	0.9	5.4
-1	1.1	6.6	1.1	6.6
1	1.2	7.8	1.2	7.8
2	1.3	9.1	1.3	9.1
3	1.5	10.7	1.5	10.7
4	2.0	12.6	2.0	12.6
5	2.4	15.0	2.4	15.0
6	2.7	17.7	2.7	17.7
7	2.7	20.4	2.7	20.4
8	2.8	23.1	2.8	23.1
9	3.5	26.7	3.5	26.7
10	3.8	30.5	3.8	30.5
11	4.1	34.6	4.1	34.6
12	4.6	39.1	4.6	39.1
13	4.8	44.0	4.8	44.0
14	5.0	49.0	5.0	49.0
15	5.3	54.3	5.3	54.3
16	5.5	59.8	5.5	59.8
17	5.7	65.5	5.7	65.5
18	5.6	71.1	5.6	71.1
19	5.1	76.2	5.1	76.2
20	4.6	80.8	4.6	80.8
21	3.0	83.8	3.0	83.8
22	2.6	86.4	2.6	86.4
23	2.3	88.7	2.3	88.7

MONTH	1x1 7F 5-SERIES		2x1 7F 5-SERIES	
	INCREMENTAL	CUMULATIVE	INCREMENTAL	CUMULATIVE
24	1.8	90.5	1.8	90.5
25	1.7	92.2	1.7	92.2
26	1.5	93.7	1.5	93.7
27	0.9	94.6	0.9	94.6
28	0.8	95.4	0.8	95.4
29	0.8	96.1	0.8	96.1
30	0.8	96.9	0.8	96.9
31	0.8	97.7	0.8	97.7
32	0.8	98.4	0.8	98.4
33	0.5	98.9	0.5	98.9
34	0.3	99.2	0.3	99.2
35	0.2	99.4	0.2	99.4
36	0.2	99.6	0.2	99.6
37	0.2	99.8	0.2	99.8
38	0.2	100.0	0.2	100.0



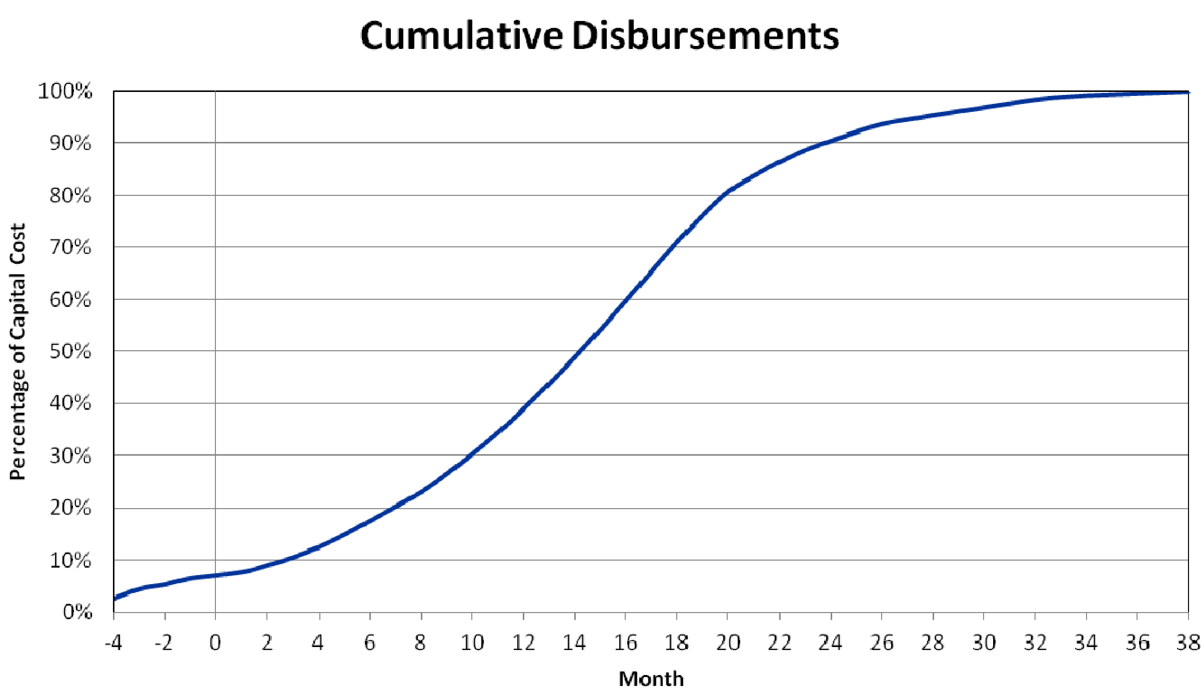
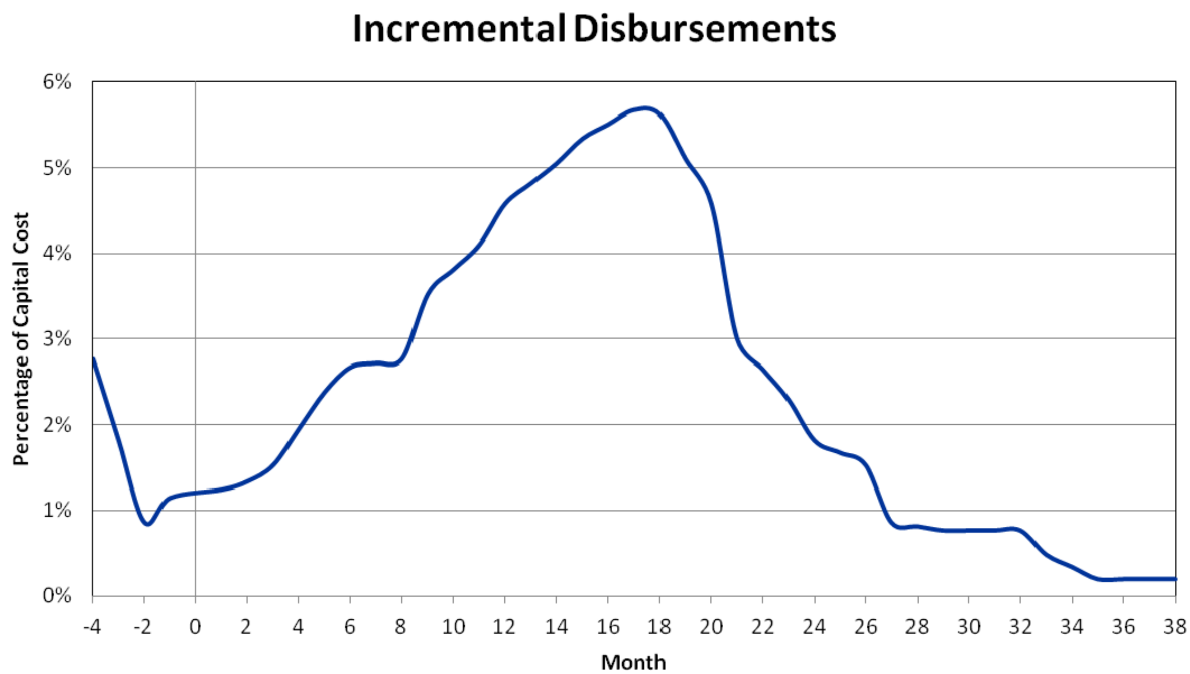


Figure 5-5 1x1 GE 7F 5-Series CCCT Cash Flow Curves



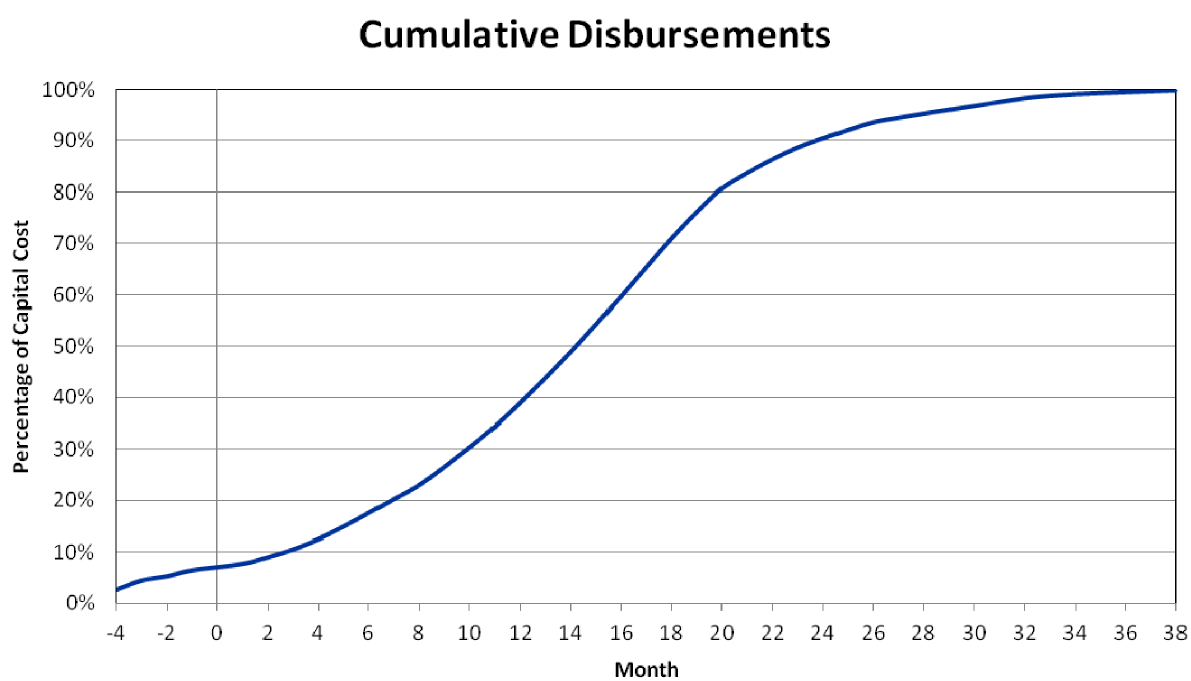


Figure 5-6 2x1 GE 7F 5-Series CCCT Cash Flow Curve

6.0 Advanced Coal Options

This section includes technology descriptions, performance and emissions, and cost characteristics for the following USCPC and IGCC technology options:

- USCPC, 600 MW.
- USCPC, 420 MW with carbon capture and compression (CCC).
- IGCC, 600 MW.

The following characteristics are addressed for each of the above options:

- Summary level technology descriptions.
- Thermal performance estimates including net plant output and net plant heat rate.
- AQCS assumptions based on probable BACT emission requirements.
- The following cost estimates are provided in 2013$:
  - Order of magnitude overnight EPC capital cost estimates.
  - Fixed and non-fuel variable O&M.
- Typical high-level outage maintenance schedule.
- Preliminary project schedule and project durations.
- Preliminary cash flow summary.

6.1 TECHNOLOGY DESCRIPTIONS

This section contains summary-level technology descriptions of USCPC and IGCC technologies.

6.1.1 Ultra-supercritical Pulverized Coal (USCPC)

6.1.1.1 Coal Combustion Operational Description

The function of a steam generator in a PC or IGCC power plant is to provide the controlled release of heat in the fuel and the efficient transfer of heat to the feedwater and steam. The transfer of heat produces main steam at the pressure and temperature required by the high-pressure (HP) turbine. Heat is also transferred through the reheater to increase the temperature of the HP turbine exhaust, or cold reheat steam, to the conditions required by the intermediate-pressure (IP) turbine. IP turbine exhaust is expanded further in the low-pressure (LP) turbine. LP turbine exhaust is condensed in a condenser. Figure 6-1 shows a high-level schematic diagram of a coal fired power plant.

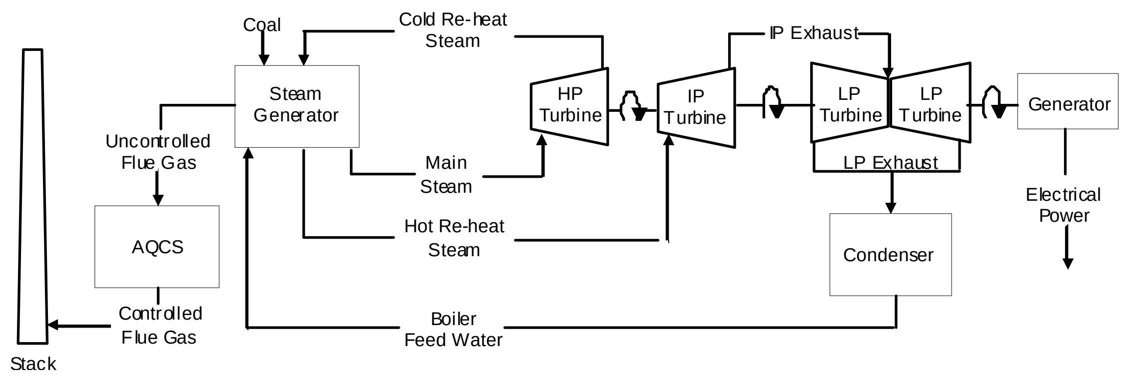


Figure 6-1 Coal Fired Power Plant Schematic Diagram

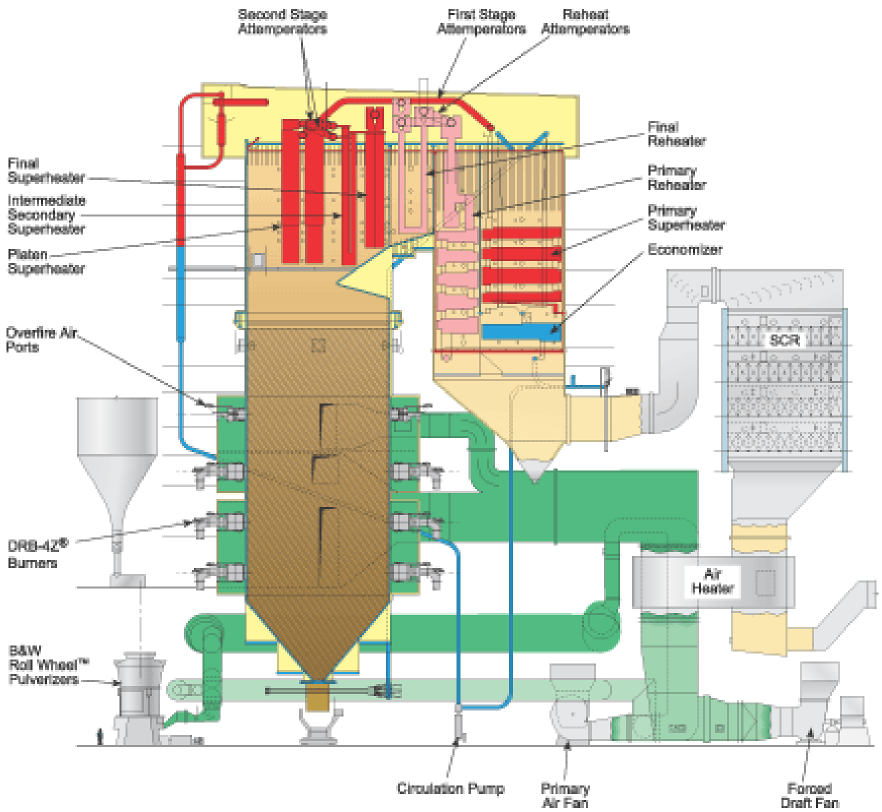
6.1.1.2 PC Steam Generators

With PC technology, coal that is sized to roughly 3/4 inch top size is fed to pulverizers that finely grind the coal so that no less than 70 percent of the coal passes through a 200 mesh screen (70 microns). This PC is pneumatically transported to multiple coal burners. At the burner, this mixture of air and coal is further mixed with secondary air (SA) and, with the presence of sufficient heat for ignition, the coal burns in suspension with the expectation that combustion will be complete before the burner flame contacts the back wall or sidewalls of the furnace. Low-NO_x burners (LNBs) and overfire air (OFA) (air and fuel staging) can be used to reduce NO_x, and carefully controlling air-fuel ratios can reduce CO emissions.

The furnace enclosure is constructed of membrane waterwalls to absorb the radiant heat of combustion. It is through the furnace waterwalls where a majority of the heat transfer from the fuel to the steam cycle occurs. Prior to the waterwalls, boiler feedwater is first fed through an economizer where the initial heat transfer takes place. Feedwater is supplied to the bottom header of the economizer from the outlet of the last HP feedwater heater. From the bottom header of the economizer, feedwater flows upward and absorbs heat within the economizer and then enters the economizer outlet header, where it is routed for heat absorption in the furnace waterwalls.

For supercritical pulverized coal (SCPC) steam generators, feedwater exits the economizer and is supplied directly to headers at the bottom of the furnace walls. Feedwater in the headers flows upwards by forced circulation through the furnace waterwall tubes in a once-through operation. Because the pressure of the feedwater is above the critical point of water (approximately 705° F and 3,200 psia), the feedwater will not boil. However, it will experience an increase in specific volume as its enthalpy increases. A “fluid” (supercritical steam) above the critical point of water is produced in the waterwalls of an SCPC steam generator, which is supplied to the primary superheater in the convective pass of the boiler. Although supercritical steam generators operate at supercritical conditions, they must start up at subcritical conditions. A startup separation system is incorporated into the design. The specific design of the separation system is unique to each manufacturer; however, most will utilize some type of separation chambers located after the furnace waterwall tubes to separate saturated steam from water.

During startup, saturated steam would be routed to the primary superheater and saturated water would typically be routed to the deaerator. A diagram of a typical SCPC steam generator is provided on Figure 6-2.



(Source: Babcock & Wilcox)

Figure 6-2 Typical Arrangement of an SCPC Boiler

Once the products of coal combustion (ash and flue gas) have been cooled sufficiently by the waterwall surfaces so that the ash is no longer molten but in solid form, heat transfer surfaces (predominantly of the convective type) absorb the remaining heat of combustion. These convective heat transfer surfaces include the primary and secondary superheaters, reheaters, and economizers located within the steam generator enclosure downstream of the furnace. The final section of boiler heat recovery is in the air preheater, where the flue gas leaving the economizer surface is further cooled by regenerative or recuperative heat transfer to the incoming combustion air.

Although steam generating surfaces are designed to preclude the deposition of molten or sticky ash products, on-line cleaning systems are provided to enable the removal of ash deposits as they occur. These on-line cleaners are typically soot blowers that utilize either HP steam or air to dislodge ash deposits from heat transfer surfaces or, in options with extreme ash deposition, utilize HP water to remove molten ash deposits from evaporative steam generator surfaces. The characteristics of the coal, such as ash content and ash chemical composition, dictate the type, quantity, and frequency of use of these on-line ash cleaning systems. Ash characteristics also dictate the steam generator design regarding the maximum flue gas temperatures that can be tolerated entering convective heat transfer surfaces. The design must ensure that ash in the flue gas stream has been sufficiently cooled so that it will not rapidly agglomerate or bond to convective heat transfer surfaces. In the case of very hard and erosive ash components, flue gas velocities must be sufficiently slow so that the ash will not rapidly erode heat transfer surfaces.

With PC combustion technology, the majority of the solid ash components in the coal will be carried in the flue gas stream all the way through the furnace and convective heat transfer components to enable collection with particulate removal equipment (electrostatic precipitators or fabric filters) downstream of the air preheater. Typically, no less than 80 percent of the total ash will be carried out of the steam generator for collection downstream. Roughly 15 percent of the total fuel ash is collected from the furnace as bottom ash, and 5 percent is collected in hoppers located below the steam generator economizer and regenerative air heaters.

6.1.1.3 State-of-the-Art Steam Generator Overview

In the United States from the early 1960s to early 1980s time frame, during the time when most existing SCPC units were completed, the cycle designs included supercritical pressures (nominally 3,600 psia) and 1,005° F main and reheat steam temperatures.

In recent state-of-the-art SCPC cycle technology in the United States, the designs include steam pressures in the range of 3,600+ psia and temperatures in the range of 1,050 to 1,080° F.

In several Electric Power Research Institute (EPRI) documents, ultra-supercritical pulverized coal (USCPC) cycle design has been defined as having a steam pressure in excess of the supercritical point pressure of 3,207 psia and steam temperatures greater than 1,100° F. This definition of ultra-supercritical appears to be universally accepted in the United States.

In recent years, a few units in the United States have been termed USCPC because they have been designed with steam temperatures in excess of 1,100° F. Most ultra-supercritical units have been completed in China, Japan, and Europe.

Improvements in the ultra-supercritical cycle design are being investigated worldwide by governmental organizations, private firms, and nonprofit organizations such as EPRI. These research and development (R&D) programs are investigating the performance improvements, cost increases, and materials of construction impacts of increasing steam pressure and temperature to realize advancements in cycle efficiency.

Today, the state-of-the-art Rankine cycle design includes steam pressures in the range of 3,700 to 4,000 psia and temperatures in the range of 1,050 to 1,120° F. Significant future advances in the cycle design parameters of pressure and temperature will be dependent on the successful development of super-alloys and fabrication techniques that can safely contain the higher steam pressures and temperatures.

6.1.2 Integrated Gasification Combined Cycle (IGCC)

Gasification is a technology with a history that dates back to the 1800s. The first patent was granted to Lurgi GmbH in Germany in 1887. By 1930, coal gasification had become widespread, and in the 1940s, commercial coal gasification was used to provide “town” gas for streetlights in both Europe and the United States. Currently, there are four main types of gasifiers:

- Entrained flow.
- Fixed bed.
- Fluid bed.
- Transport bed.

Gasification consists of partially oxidizing a carbon-containing feedstock (solid or liquid) at a high temperature (2,500 to 3,000° F) to produce a syngas consisting primarily of CO and hydrogen. A portion of the carbon is completely oxidized to CO_2 to generate sufficient heat for the endothermic gasification reactions. The CO_2 proportion in the syngas from the gasifier ranges from 1 percent for the dry feed gasifiers (MHI [Mitsubishi Heavy Industries], Shell, Siemens, and Uhde) to more than 15 percent for the slurry fed COP and GE gasifiers. The gasifier operates in a reducing environment that converts most of the sulfur in the feed to hydrogen sulfide (H_2S). A small amount of sulfur is converted to carbonyl sulfide (COS). Other minor syngas constituents include ammonia (NH_3), hydrogen cyanide (HCN), hydrogen chloride (HCl), and entrained ash, which contains unconverted carbon. In IGCC applications, the gasifier pressure is typically 450 to 550 psig. This pressure is determined by the CTG syngas supply pressure requirements. GE gasifiers operate at higher pressures, up to 1,000 psig, and the excess syngas pressure is let down in an expander to produce additional power.

A fluxant is fed with the coal to control the slag viscosity so that it will flow out of the gasifier. Fluxant addition is less than 2 percent of the coal feed. The fluxant can be limestone, PC boiler ash or, in some options, dirt. The required fluxant composition and proportion will vary with the coal feed composition. The gasification process operators must know the feed coal composition and make fluxant adjustments when the coal composition changes. Too little fluxant can allow excessive slag to accumulate in the gasifier, which could damage the refractory and eventually choke the gasifier. Too much fluxant can produce long cylindrical slag particles instead of small slag granules when the slag is quenched in the lockhopper. These long thin slag particles will plug up the slag lockhopper.

Solid fuel feeds to the gasifier can be dry or slurried. Solid fuels slurried in water do not require the addition of steam for temperature moderation. While slurries typically use water, oil can also be used. Steam is added to the oxygen as a temperature moderator for dry solid feed gasifiers, solid feeds slurried in oil, and oil feed gasifiers.

6.1.2.1 Entrained Flow Gasifiers

Entrained flow gasifiers have been operating successfully on solid fuels since the mid-1980s to produce chemicals, and since the mid-1990s, to produce electricity in four 250 to 300 MW IGCC plants located in Europe (two units) and the United States (two units). At this time, based upon their characteristics and level of development, entrained flow gasifiers are the best choice for high capacity gasification for power generation.

Entrained flow gasifiers use oxygen to produce syngas heating values in the range of 250 to 300 Btu/scf on an HHV basis. An oxygen concentration of 95 percent by volume is the economic optimum for IGCC plants using entrained flow gasifiers that only produce power. (Higher oxygen concentrations are optimum when most of the syngas is used to produce hydrogen.) Oxygen is produced cryogenically by compressing air, cooling and drying the air, removing CO_2 from the air, chilling the feed air with product oxygen and nitrogen, reducing the air pressure to provide autorefrigeration and liquefy the air at -300° F, and separating the liquid oxygen and liquid nitrogen by distillation. Air compression consumes a significant amount of power, between 13 and 17 percent of the IGCC gross power output.

Hydrogen in syngas prevents the use of DLN combustors in the CTGs. The dilution of the syngas to reduce flame temperature is required for NO_x control. Syngas can be diluted by adding water vapor and/or nitrogen. Water vapor can be added to the syngas by evaporating water using low level heat. Nitrogen can be added by compressing excess nitrogen from the air separation unit (ASU) and adding it to the syngas, either upstream of the CTG or by injection into the CTG. Syngas dilution for NO_x control increases the mass flow through the CTG, which also increases power output.

A portion of the CTG compressed air may be extracted for feed to the ASU. The ASU and combined cycle are integrated by the nitrogen and air exchanges. Extracting compressed air from the CTG improves overall efficiency, but it adds complexity to the process, including longer startup periods, if there is no separate source of startup compressed air.

The raw hot syngas is cooled by the boiler feedwater from the HRSG to a temperature suitable for cleaning. The syngas cooling process generates steam. The steam quantities and pressures vary with the gasification process design. Gasification steam is subsequently integrated into the steam cycle.

Before raw syngas enters the CTG combustor, the H_2S, COS, NH_3, HCN, and particulates must be removed. Cooled syngas is scrubbed to remove NH_3, water soluble salts, and particulates. Syngas may also be filtered to remove additional particulates. COS in the syngas is hydrolyzed by a catalyst to H_2S, which is removed from the syngas by absorption in a solvent. This absorption process is called acid gas removal (AGR).

The H_2S that is removed from the syngas by absorption in a solvent is desorbed as a concentrated acid gas when the solvent is regenerated by lowering its pressure and increasing its temperature. The acid gas stream is converted to elemental sulfur in the Claus sulfur recovery process. The primary chemical reaction in the Claus process is the reaction of H_2S and SO_2 to produce elemental sulfur and water. This reaction requires a catalyst and is performed in two stages. The SO_2 is produced by oxidizing (burning) one third of the H_2S in the feed gas. External fuel is only needed to initially heat up the Claus thermal reactor and initiate combustion of the acid gas. Under normal operation, the oxidation of H_2S provides sufficient heat to maintain the reaction.

The sulfur is formed as a vapor. The S_2 form of sulfur reacts with itself to produce S_6 and S_8, which are subsequently condensed. This condensed liquid sulfur is separated from the residual gas and stored in a pit at 275 to 300° F. As required, the liquid sulfur is pumped from the pit to railcars for shipment. Solid sulfur can be produced in blocks or pellets by cooling the liquid sulfur to ambient temperature. The residual (tail gas) is primarily CO_2 and nitrogen, which are compressed and re-injected into the syngas upstream of the AGR.

An IGCC schematic diagram for commercially available units is provided in Figure 6-3.

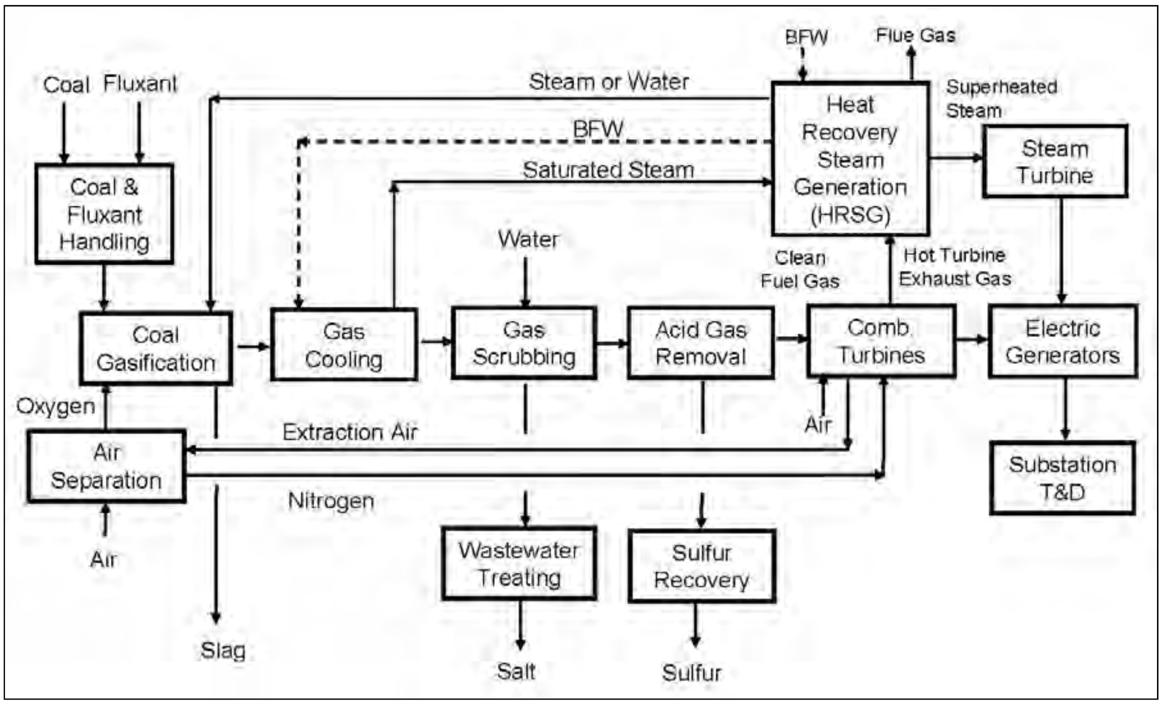


Figure 6-3 IGCC Schematic Diagram

6.1.2.2 Gasifier Technology Suppliers

Although there have been relatively few major players in the recent past for the large scale, solid fuel, gasifier market, the list of established vendors is beginning to increase. Although the quantity and type (e.g., IGCC, chemicals) of experience of some of the major gasifier vendors varies significantly, Black & Veatch believes that the following vendors have well established technologies that provide good options for current IGCC applications.

- CB&I, which licenses E-Gas technology that was developed by Dow. CB&I purchased this technology from COP in March 2013.
- GE, which purchased Texaco gasification technology from ChevronTexaco in June 2004. GE offers both Quench and Radiant (high temperature heat recovery [HTHR]) cooler gasifiers.
- MHI, which is an air blown (oxygen enriched), dry feed gasifier that is being developed specifically for IGCC applications.
- Shell, which developed its gasification technology in conjunction with Prenflo.
- Siemens, which currently uses a full spray quench design and is developing a partial quench design.
- Uhde, which re-entered the gasifier vendor market after their agreement with Shell expired in late 2008.

Although there are many other gasifier vendors, Black & Veatch does not believe that other gasifier technology suppliers are strong competitors in the utility-scale IGCC market because of the relative maturity of their technology or because of inherent technology drawbacks for IGCC applications.

The E-Gas and GE gasifiers are refractory lined with coal-water slurry feed. The GE quench gasifier is used extensively in chemical plants around the world. GE has been expanding their commercial offering to larger scales to meet demand for larger chemical plants and large scale IGCC plants. E-Gas has significantly less experience than GE, but is one of the only gasifiers with a demonstration scale IGCC plant operating on solid fuel.

Shell and Krupp-Koppers (now Uhde) jointly developed a waterwall type gasifier with dry, PC feed specifically for IGCC power generation in the late 1970s for a 150 long tons per day (ltpd) demonstration plant near Hamburg, West Germany. During the 1990s, Shell and Krupp-Koppers licensed their gasification technology separately. The Puertollano, Spain, IGCC plant, which was built in the mid-1990s, uses Krupp-Kopper's Prenflo gasification technology. In the late 1990s, Krupp-Koppers merged with Uhde; Uhde reached an agreement with Shell to license Shell gasification technology. In 2008 Uhde did not renew their agreement with Shell and now offers the PRENFLO gasifier as a commercial offering.

Siemens and MHI are relatively new to the commercial scale solid fuel gasification market. Siemens purchased their gasification technology from Future Energy in 2006. The technology was developed at the Deutche Brennerstoffinstitute (DBI) and was owned and developed by several companies before Future Energy. Siemens has been aggressively marketing their technology for chemicals and substitute natural gas applications, but is also interested in the IGCC market. In contrast, MHI is focused almost entirely on the IGCC market and has developed their technology with that in mind. MHI is not an oxygen blown gasifier, but does use an ASU to supply nitrogen for its dry feed process to the gasifier. The oxygen produced in the ASU is used to enrich the air used in the gasification process. MHI developed a 250 MW IGCC plant (Nakoso) in Iwaki City, Japan that began construction in 2004 and was completed in 2007. The plant has completed several thousand hours of operation to date.

With the exception of the MHI gasifier, each of the commercial entrained flow coal gasification technologies generates similar syngas products. The gasifiers react coal with oxygen and water at high-pressure and high temperature to produce syngas consisting primarily of hydrogen and CO. The raw syngas from the gasifier also contains CO_2, water, H_2S, COS, NH_3, HCN, and other trace impurities (the MHI gasifier also has significant quantities of N_2). The syngas exits the gasifier reactor at approximately 2,500 to 2,900° F.

Each of the gasification processes cools the hot syngas from the gasifier reactor differently. In the E-Gas process, the hot syngas is partially quenched with coal slurry, resulting in a second stage of coal gasification. The chemically quenched syngas is further cooled to produce steam in a fire tube heat exchanger. (Syngas flow is through the tubes. Boiler water and steam flow is on the shell side.) Unconverted coal is filtered from the cooled syngas and recycled to the gasifier's first stage. GE has two methods for cooling the hot syngas from the gasifier; radiant cooling to produce HP steam via HTHR and water quench followed by low-pressure (LP) steam generation. The MHI gasifier uses a chemical quench cooling similar to E-Gas, but with a dry feed, followed by a water tube convective syngas cooler that produces HP steam for the steam turbine. In the Shell and PRENFLO processes, hot syngas is cooled with recycled syngas to solidify the molten fly slag and then further cooled in a convective cooler to produce high temperature steam. The Siemens gasifier uses a water spray to quench the syngas to saturation conditions. Although they are developing a partial water quench with subsequent heat recovery, the lack of steam generation explains in part Siemens' focus on chemical plants rather than power generation.

The cooled, raw syngas is cleaned by various treatments, including filtration, scrubbing with water, catalytic conversion, and scrubbing with solvents. The clean syngas used as CTG fuel contains hydrogen, CO, CO_2, water, and ppm concentrations of H_2S and COS.

Table 6-1 provides process design characteristic data for the E-Gas, GE, MHI, Shell, Siemens, and PRENFLO gasification technologies for systems that would generally be considered for a utility scale facility. The Shell and PRENFLO gasification technologies have the highest cold gas efficiency, because the gasifier feed coal is injected into the gasifier dry, whereas with the E-Gas and GE gasifiers, the feed is a slurry of coal in water. However, the Shell dry feed coal gasification process has a higher capital cost. Cooling the hot syngas to produce HP steam also contributes to higher IGCC efficiency, but with a higher capital cost. Shell and E-Gas generate HP steam from syngas cooling. GE offers both HP steam generation using radiant and convective syngas coolers and LP steam generation using its quench process, which has a significantly lower capital cost. The E-Gas and GE gasifiers are refractory lined, while the Shell gasifier has an inner water tube wall (membrane). The refractory lined gasifiers have a lower capital cost, but the refractory requires frequent repair and replacement. The COP and GE gasifier burners typically require more frequent replacement than the Shell gasifier burners.

It is worth mentioning that gasifier sizing issues exist with respect to the Shell and GE Quench technologies. Shell has stated that its maximum gasifier capacity is 5,000 short tons per day (stpd) of dried coal, which is large enough to supply syngas to two GE 7F-Syngas (SG) or Siemens SGT6-5000F CTGs. GE offers gasifiers in three standard sizes: 750, 900, and 1,800 ft^3. The largest quench gasifier that GE currently offers is the 900 ft^3 size. The maximum capacity of this quench gasifier is less than 2,500 tpd of as-received coal and does not produce enough syngas for a GE 7F-SG or Siemens SGT6-5000F CTG. The largest radiant gasifier that GE currently offers is 1,800 ft^3 and will supply sufficient syngas for a GE 7F-SG or Siemens SGT6-5000F CTG. E-Gas currently offers a gasifier that will supply sufficient syngas for a GE 7F-SG or Siemens SGT6-5000F CTG.

Overall, energy conversion efficiencies for IGCC plants vary with the gasification technology type, system design, level of integration, and coal composition. The gasifier efficiency of converting the coal fuel value to the syngas fuel value, after sulfur removal, is known as the cold gas efficiency, which is generally expressed in HHV. The values for cold gas efficiency in Table 6-1 are indicative of the range of achievable performance for coal and petcoke. Cold gas efficiency for the Shell dry coal feed process is about 3 percent higher than the coal-water slurry feed gasification processes for low moisture coal. This difference increases with coal moisture content. HP steam generation from syngas cooling increases IGCC efficiency by about 2 percent over that of water quench.

Table 6-1 Comparison of Key Gasifier Design Parameters

PARAMETER	E-GAS	GE QUENCH	GE RADIANT	SHELL	SIEMENS	MHI	PRENFLO
Gasifier Feed Type	Slurry	Slurry	Slurry	Dry N_2 Carrier	Dry N_2 Carrier	Dry N_2 Carrier	Dry N_2 Carrier
Gasifier Burners	Two-Stage: First Stage--Two horizontal burners Second Stage--One horizontal feed injector without O_2	Single-Stage--One vertical burner	Single-Stage--One vertical burner	Single-Stage--Four to eight horizontal burners	Single-Stage--One or more vertical burners	Two Stage: First Stage--Two horizontal burners Second Stage--One horizontal injector	Single-Stage--Four horizontal burners
Gasifier Vessel	Refractory lined	Refractory lined	Refractory lined	Waterwall membrane	Water screen	Water Wall membrane	Water Wall membrane
Syngas Quench	Coal slurry and recycle gas	Water Bath	None	Recycle gas	Water Spray	Chemical	Recycle gas
Syngas Heat Recovery	Firetube HP waste heat boiler (WHB)	Quench LP WHB	Radiant HP WHB	Watertube HP WHB	Quench LP WHB	Watertube HP WHB	Watertube HP WHB
Coal Cold Gas Efficiency, HHV	71 to 80 percent	69 to 77 percent	69 to 77 percent	78 to 83 percent	78 to 83 percent	70 to 75 percent	78 to 83 percent
Coal Flexibility	Middle	Low	Low	High	High	High	High
Capacity, stpd	3,000 to 3,500	1,500 to 2,000	2,500 to 3,000	4,000 to 5,000	1,500 to 4,000	1,700	2,500 to 4,000

There are three general coal feedstocks typically considered for US IGCC projects: Pittsburgh No. 8, Illinois No. 6, and PRB. Petcoke is a fourth solid fuel feedstock that is frequently considered for IGCC applications.

Coal-based operating experience has been focused almost exclusively on bituminous coals (e.g., Pittsburgh No. 8 and Illinois No. 6), and there is also extensive experience with petcoke. Subbituminous (i.e., PRB) coals have been tested only in a limited fashion, but due to the nature of the US coal market and the abundance of PRB coal, there is strong interest in using it for IGCC applications. The assumed fuel for this study is PRB.

In the E-Gas and GE gasification processes, the high inherent moisture in PRB coal approximately doubles the total water content in the coal slurry per pound of dry coal to the gasifier. Vaporizing all of this water requires the combustion of more than 10 percent of the carbon in the coal to CO_2, which reduces gasifier efficiency. In the E-Gas gasification process, a portion of the coal slurry is injected into the hot raw gas from the first stage, where the coal is partially oxidized. This second-stage quench partially gasifies the injected coal. The unreacted, dry coal is filtered out of the gas and recycled to the first stage. This dry recycle step improves gasifier efficiency for PRB coal relative to the GE gasification process, but the E-Gas gasification process is much less efficient and more expensive than the Shell gasification process for PRB coal.

In the GE gasification process, all of the inherent water in the coal and the liquid water in the slurry must be evaporated in the gasifier by combusting more CO to CO_2, which results in a lower cold gas efficiency than the E-Gas and Shell gasification processes. Therefore, the GE gasification process has not been considered economical for PRB coal.

The high moisture content in PRB coal is reduced to 2 to 5 percent (by weight) during milling/drying in the Shell gasification process so that there is minimal impact on gasifier performance. The mill is swept with hot nitrogen or flue gas from combusted syngas. The dried, pulverized coal is separated from the wet gas and conveyed with dry nitrogen to an elevated silo; then it is sent to a lockhopper, where it is pressurized above the gasifier operating pressure and sent to a feed bin; and, finally, it is sent to the gasifier. After drying, the coal is kept under a nitrogen atmosphere to prevent fires until it is inside the gasifier.

The intent of the study was not to compare or provide data for all of the utility scale commercially available gasification technologies. Because the Shell coal gasification process lends itself well to high moisture fuels such as PRB, the assumed design fuel for this study, the Shell process was selected as being representative of the commercially available gasification technologies. In regards to IGCC, the remainder of the study focuses on the Shell coal gasification process.

6.1.3 Carbon Capture and Compression

Carbon capture is a mature technology in the chemical processing industry and is an integral part of many processes such as synthetic ammonia production, hydrogen (H_2) production, and limestone calcination. However, large-scale carbon capture from conventional coal power generation technologies in its preliminary stages of demonstration.

Carbon capture can be applied before or after combustion. In pre-combustion capture, the masses and volumes of the treated gas streams are smaller and easier to handle. Pre-combustion capture can be utilized in integrated gasification combined cycle (IGCC) power plants where the supply fuel (syngas) is at a high pressure. The syngas typically contains a large fraction of carbon monoxide (CO) that can be shifted with water to form CO_2 and hydrogen (H_2) before combustion, facilitating the CO_2 capture process. The high pressure syngas enables the use of physical solvents (e.g. Selexol) for CO_2 absorption and separation. A physical solvent's capacity to absorb CO_2 increases with increasing pressure and also with decreasing temperature.

Post-combustion carbon capture would typically be utilized in PC and natural gas combined cycle (NGCC) power plants. Flue gas streams have very large masses and volumes with relatively low concentrations of CO_2. The flue gas pressure is also near ambient and requires a chemical solvent to achieve CO_2 capture. The effectiveness of chemical solvents for CO_2 absorption and separation is nearly independent of pressure making them more suitable for post-combustion capture.

Once captured, CO_2 may be stored by means of oceanic or geological sequestration. Long-term sequestration of CO_2 has yet to be proven as a definitive technology and may not be feasible in some geographic regions. Two current practical uses of CO_2 are in the enhanced oil recovery (EOR) industry and for general use as an industrial gas. The cost of sequestration is likely a key to the feasibility of carbon capture for any given project.

Another aspect about sequestration that will become more prevalent in the coming years is delineation of liability for sequestration operations and effectiveness of long-term storage. These will be shaped by how CO_2 is classified as a material for storage, property rights and use issues, and ownership and responsibility of the stored CO_2. These areas of law are currently in the formative stages.

Amine-based scrubbing technologies including the use of an aqueous solution of Monothethanolamine (MEA) are among the most developed technologies for carbon capture applications. MEA is a simple alkanolamine with a hydroxyl group and an amine group. The hydroxyl group reduces the vapor pressure of the MEA and increases its solubility in water. The amine group provides the alkalinity that is required to absorb acid gases. MEA chemically absorbs CO_2 from a gas stream to form an amine salt according to the following reaction.

$$2RNH_2 + CO_2 \rightleftharpoons RNHCOONH_3R$$

Because the product in this reaction has an appreciable vapor pressure, the composition of the equilibrium solution varies with the partial pressure of the CO_2. The vapor pressure of the product also increases with temperature so absorption of CO_2 takes place at a low temperature and stripping takes place at a higher temperature. The stripping process typically requires significant quantities of low pressure process steam. In addition to the main reversible reaction with CO_2, MEA also undergoes irreversible reactions with carbonyl sulfide and carbon disulfide, limiting its effectiveness in treating gas streams with appreciable quantities of these contaminants.

A typical post-combustion CO_2 removal process for a PC power plant using an MEA solvent consists of flue gas preparation in a typical air quality control system, CO_2 absorption, CO_2 stripping, and CO_2 compression. The flow process begins at the flue gas discharge from the plant emissions controls equipment, where a blower with a cooler is used to pass the flue gas upward through an absorber. Cool MEA solution is distributed evenly downward through the absorber onto packing material, allowing the solvent to selectively capture CO_2 from the flue gas. The flue gas exiting the absorber is washed with water to recover any amine compounds and is then discharged from the top of the absorber through a stack to the atmosphere. The solvent with the captured CO_2 (CO_2-rich solution) is collected at the bottom of the absorber, pre-heated via an amine/amine heat exchanger, and pumped into the top of a stripper. CO_2 is stripped from the solvent by steam from the reboiler. The resulting CO_2 is then dehydrated, compressed, and transported to storage.

Amine-based CO_2 capture is well understood in industrial applications, such as ammonia and hydrogen production. However, large-scale CO_2 capture for a PC facility has not been demonstrated. Despite the lack of commercial demonstration in the power industry, amine-based post-combustion CO_2 capture is not expected to significantly affect operations of other plant equipment, since the entire process takes place downstream of the power block. The overall complexity of the PC facility would increase, and the capture process may require additional staffing, compared to a PC facility without CCC.

Because the use of this technology has not been demonstrated at scale in the power industry, there is a scale-up risk to implement amine-based post-combustion CO_2 capture in its current state. It is expected that improvements and optimizations will be forthcoming from current and future development work. At this time, capital and operating costs are high, particularly for initial installations. However, opportunities exist to reduce these costs as the process is optimized through operating experience. Currently advancement of amine technology for coal based power plants is taking place at various places in the US and abroad.

The EPA's rulemaking on Greenhouse Gas (GHG) New Source Performance Standards (NSPS) for new units is expected to require carbon capture and sequestration (CCS) on any future coal units. The EPA, under directive of the President of the US, issued a pre-publication copy of the revised NSPS for new units on 20 September 2013. The presidential order only indicates that the EPA must finalize the rule "in a timely fashion after considering all public comments, as appropriate." In that proposal, "the EPA is basing the standards for new fossil fuel-fired utility boilers on partial CCS technology operating to a level of 1,100 lb CO_2/MWh. Partial CCS designed to meet an emission standard of 1,100 lb CO_2/MWh would also achieve significant emission reductions, emitting on the order of 30 to 50 percent less CO_2 than a coal-fired unit without CCS. Finally, a standard based on partial CCS clearly promotes implementation and further development of CCS technologies, and does so as much as, and perhaps even more than, a standard based on a full capture CCS requirement would."

6.2 PERFORMANCE AND EMISSIONS

This section presents estimates of thermal performance for the USCPC and IGCC technologies.

6.2.1 USCPC

For the purpose of the evaluation, the USCPC technologies were evaluated on a consistent basis relative to one another. Arrangement assumptions specific to each of the USCPC options, which were used in the development of the estimates, are summarized in Table 6-2.

The performance data include net plant output and net plant heat rate at 100, 75, 50, and 30 percent net loads. The minimum load for a USCPC unit varies according to design and other considerations, but 30 percent is a reasonable estimate. Performance estimates were generated on the basis of average-day ambient temperatures, as defined in Section 2.1. The performance estimates are for new and clean units at rated flow and do not include the effects of degradation. The performance estimates reflect units firing PRB coal.

Performance estimates for the coal technologies with and without CCC are provided in Table 6-3. Estimated emissions and limits for the USCPC technology are provided in Table 6-4. The air emissions data include CO_2, CO, SO_2, NO_x, Hg, and particulate matter.

The emissions estimates were based on the assumed AQCS, which is reflective of expected future BACT requirements. Future regulations may result in more stringent requirements depending on the EPA's GHG NSPS yet to be published. The following AQCS were selected as the design basis for the purpose of developing performance and cost estimates. Actual emissions limits are determined on a case-by-case basis as a result of the permitting process; however, it is anticipated that actual project permitted limits could fall within these ranges.

The AQCS were selected as a design basis to develop performance and cost estimates and to meet more stringent air quality requirements. The actual AQCS would be selected to control criteria pollutants under a Prevention of Significant Deterioration (PSD) permit and would be subject to BACT review. As of June 2009, mercury (Hg) limits had been removed from the EPA NSPS. This currently leaves Hg as a hazardous air pollutant (HAP), which may be subject to a MACT review.

Based on the widely reported political and environmental challenges that face any proposed coal project in today's domestic marketplace and given a normal permitting process, a coal project may need to assume the more stringent air quality control basis in order to have a greater chance of being approved by the regulating agencies. As would be expected, these systems will have higher capital and annual O&M costs in order to realize the lower emissions rates.

Table 6-2 USCPC Cycle Arrangement Assumptions

STEAM GENERATOR	USCPC	USCPC W/ CCC
Net Plant Output, MW	600	420
Number of Steam Generators	1	1
Reheat Cycle	Yes	Yes
Steam Turbine	Supercritical TC4F-33.5	Supercritical TC4F-33.5
Main Steam Pressure/Temperature, ° F, psia	4,000/1,110	4,000/1,110
Reheat Steam Pressure/ Temperature, ° F, psia	660/1,130	660/1,130
Boiler Feed Pump Drive	Motor	Motor
Auxiliary Power, percent (1)	9.5	36.7
Cycle Heat Rejection	Wet MDCT	Wet MDCT
Fuel Supply	PRB	PRB
HP Feedwater Heaters, count	3	3
LP Feedwater Heaters, count	4	4
Total Feedwater Heaters, count (2)	8	8
NO_x Control, Post-Combustion	SCR	SCR
SO_2 Control, Post-Combustion	Wet FGD	Wet FGD
CO_2 Control, Post-Combustion	none	Amine Based CC
Particulate Control	Fabric Filter	Fabric Filter
Hg Control	ACI	ACI

Notes:
1. Auxiliary power is assumed as a percentage of gross plant output at full load.
2. Each unit would utilize one deaerator feedwater heater.
3. MDCT = Mechanical draft cooling tower.

Table 6-3 USCPC Thermal Performance Estimates

CONFIGURATION	LOAD, PERCENT	GROSS PLANT OUTPUT, KW	AUXILIARY LOAD, PERCENT	AUXILIARY LOAD, KW	NET PLANT OUTPUT, KW	NET PLANT HEAT RATE (HHV), BTU/KWH
600 MW USCPC	100	663,000	9.5	63,000	600,000	9,290
	75	505,000	10.9	55,000	450,000	9,560
	50	349,000	13.9	49,000	300,000	10,150
	30	223,000	19.3	43,000	180,000	11,280
420 MW USCPC w/ CC	100	663,000	36.7	243,000	420,000	13,453
	75	515,360	38.9	200,360	315,000	14,125
	50	371,800	43.5	161,800	210,000	15,685
	30	259,360	51.4	133,360	126,000	18,997

Table 6-4 USCPC Estimated Future Air Emissions Limits and Removal Efficiencies

	USCPC	USCPC W/CCC
NO_x, lb/MBtu (HHV) (1)	0.04 to 0.06	0.04 to 0.06
SO_2, lb/MBtu (HHV) (1)	0.04 to 0.08	0.04 to 0.08
PM_{10} (filterable), lb/MBtu (HHV) (1)	0.010 to 0.012	0.010 to 0.012
Hg removal efficiency, percent	90 to 95	90 to 95
Hg, lb/MBtu(2)	4.9 x 10^{-6} (uncontrolled), 4.9 x 10^{-7} (controlled at 90 percent removal)	4.9 x 10^{-6} (uncontrolled), 4.9 x 10^{-7} (controlled at 90 percent removal)
CO_2, removal efficiency, percent	N/A	90
CO_2, lb/MBtu (HHV)	210 to 215	21 to 22 (3)
CO, lb/MBtu (HHV)	0.10 to 0.15	0.10 to 0.15

Notes:
1. Indicative emissions limit range is representative of expected future requirements.
2. Based on emission factors from EPA AP42.
3. Approximate CO_2 emissions with 90 percent removal.
4. All values provided above are preliminary estimates with no guarantees.
5. The above estimates may differ from actual emissions, based on actual permitting requirements and actual AQCS capabilities.
6. CO_2 estimated air emissions limits are representative of PRB fuel.

The assumed AQCS for the USCPC technologies are the same as provided in Section 6.2.1 with the addition of CCC. It was assumed that an amine based CCC AQCS would be utilized. The estimates do not include CO_2 transportation and sequestration as this aspect is unknown and very project specific.

6.2.2 IGCC

IGCC technology has different issues that need to be considered. Unlike USCPC units, an IGCC unit IGCC unit cannot be sized to match a selected net plant output. The constraints are a SCCT or CCCT unit. CTGs come in discrete sizes and are much more sensitive to elevation and ambient temperature than a USCPC plant. Arrangement assumptions IGCC case used in the development of the estimates are summarized in Table 6-5. The IGCC performance estimates, shown in

Table 6-6 are reflective of units gasifying PRB coal and operating at the average-day ambient temperature, as defined in Section 2.1. Full-load air emissions estimates for the IGCC option are summarized in

Table 6-7. The air emissions data include CO_2, CO, SO_2, NO_x, Hg, and particulate matter. Rates for byproduct sulfur and slag/fly ash are also provided along with the air emissions estimates.

Table 6-5 IGCC Cycle Arrangement Assumptions

GASIFIER TECHNOLOGY	SHELL
Nominal Net Plant Output, MW	600
Number of Gasifiers, count	2
CTG Technology	GE 7F-SG (1)
Number of CTGs, count	2
Number of HRSGs, count	2
Steam Turbine	Subcritical TC2F-33.5
Throttle Conditions, psia / ° F	1,565 / 1,000
Cycle Heat Rejection	Wet Mechanical Draft Cooling Tower
NO_x Control	Nitrogen diluent, syngas saturation, and SCR
SO_2 Control	Pre-combustion acid gas removal
CO Control	None (2)
Particulate Control	Candle filter
Hg Control	Sulfided carbon bed
Boiler Feed Pump Drive	Motor
Note: Previously known as the 7FB syngas CTG which was a specially modified 7FB natural gas CTG. The 7FB natural gas CTG is no longer being offered and has since been replaced with the 7F 5-Series.	

Table 6-6 IGCC Thermal Performance Estimates

CONFIGURATION	2x1 IGCC
Nominal Capacity, MW	600
Coal to Gasifiers, as-received, stpd	7,184
Gasifier Cold Gas Efficiency (Clean Syngas HHV/Coal HHVx100), percent	83
Syngas to CTG(s) (LHV), MBtu/h	3,762
CTG(s) Gross Output, MW	452
Steam Turbine Gross Output, MW	262
Gross Plant Output, MW	714
Auxiliary Power Consumption & Losses, MW	146
Net Plant Output, MW	568
Net Plant Heat Rate (HHV), Btu/kWh	8,800

Table 6-7 IGCC Emissions Estimates

CONFIGURATION	2x1 IGCC
Nominal Capacity, MW	600
NO_x, lb/MBtu (1)	0.01 to 0.02
SO_2, lb/MBtu (1)	0.03 to 0.10
PM_{10} (filterable), lb/MBtu (1)	0.007 to 0.011
Hg, percent removal efficiency	90 to 95
Hg, lb/MBtu(2)	4.9×10^{-6} (uncontrolled), 4.9×10^{-7} (controlled at 90 percent removal)
CO, lb/MBtu	0.03 to 0.04
CO_2, lb/MBtu	210 to 215
Byproduct Sulfur, ltpd	22
Byproduct Slag/Fly Ash, stpd	366

Notes:
1. Indicative emissions limit range representative of expected future requirements.
2. Based on emission factors from EPA AP42.
3. All values provided above are preliminary estimates with no applied guarantees.
4. The above estimates may differ from actual emissions based on actual permitting requirements and actual AQCS capabilities.
5. CO_2 is representative of PRB fuel.

The assumed AQCS for the IGCC technology is provided as follows:

- IGCC:
  - NO_x:
    - Nitrogen dilution.
    - Syngas saturation.
    - SCR.
  - CO: None; space would be allocated for the future addition of CO oxidation catalysts in the HRSG.
  - SO_2:
    - COS hydrolysis.
    - Selexol acid gas removal.
    - Claus SRU with tailgas recycle.
  - PM_{10}-- Candle filter.
  - Hg-- Sulfided carbon bed.

6.3 CAPITAL COSTS

Market-based, order of magnitude overnight EPC capital and total project cost estimates were generated for each of the USCPC and IGCC technologies. An EPC cost basis, exclusive of Owner's costs, was utilized. Typically, the scope of work for an EPC cost is the base plant, which is defined as being "inside the fence" with distinct boundaries and terminal points. A total project cost estimate is defined as the EPC capital cost plus an Owner's Cost Allowance. The Owner's Cost Allowance was assumed as a percentage of the EPC capital cost.

The cost estimate includes estimated costs for equipment and materials, construction labor, engineering services, construction management, indirect costs, and other costs. The estimates were based on Black & Veatch proprietary estimating templates and experience. The estimates are order of magnitude estimates prepared for the purposes of project screening, resource planning, comparison of alternative technologies, etc., and as such, are expected to be in the range of ±30 to 40 percent of actual project costs.

6.3.1 USCPC

Order of magnitude, overnight EPC capital cost and total project cost estimates for USCPC technologies are shown in Table 6-8 below.

Table 6-8 USCPC EPC Capital Cost Estimates, 2013$

DESCRIPTION	600 MW_{NET} USCPC	420 MW_{NET} USCPC W/ CCC
Total Direct Costs, $1000	1,100,000	1,970,000
Total Indirect Costs, $1000	425,000	758,000
Net Plant Output, kW	600,000	420,000
EPC Cost, $1,000	1,525,000	2,728,000
EPC Unit Cost, $/kW	2,542	6,495
Owner's Cost Allowance, percentage of EPC Cost	45	45
Owner's Cost Allowance, $1,000	686,000	1,228,000
Total Project Cost, $1,000	2,211,000	3,956,000
Total Project Cost, $/kW	3,685	9,419

Notes:
1. All EPC cost estimates are presented in 2013 dollars. The costs are order of magnitude estimates and, as such, are expected have an accuracy of ± 30 percent of the EPC cost.
2. EPC costs are exclusive of Owner's costs.
3. Unit EPC capital cost was based on net plant output.
4. The sum of the turnkey EPC cost and the Owner's costs will give a total project cost. An Owner's Cost Allowance of 45 percent of the EPC Cost was used.

Power plant costs will be subject to continued volatility in the future, and the estimates in this report should be considered primarily for comparative purposes.

The following listing provides general EPC capital cost estimating assumptions. The general assumptions identify the scope of supply included in the EPC capital cost estimate. Assumptions related to the development of the performance estimates also apply to the EPC cost estimates. Assumptions related to direct and indirect costs and Owner's costs were provided in Section 2.3. Overall site assumptions were also provided in Section 2.4. Capital cost estimating assumptions for the USCPC technology include:

1. Steam turbine: nominal 660 MW Unit, tandem-compound, four-flow, single-reheat machines (TC4F).
2. Electric generator.
3. Steam systems:
    a. Main steam system.
    b. Main steam bypass system.
    c. Cold reheat steam system.
    d. Hot reheat steam system.
    e. Extraction steam system.
4. Extraction drains.

5. Condensate system:
    a. Steam surface condenser--two-shell, dual-pressure, stainless steel tubes.
    b. Condenser vacuum pumps.
    c. Vertical condensate pumps.
    d. Deaerator.
6. Feedwater system:
    a. LP feedwater heaters.
    b. HP feedwater heaters.
    c. Electric boiler feedwater pumps.
7. Circulating water system:
    a. Circulating water pumps.
    b. Wet, multi-cell, rectangular, mechanical induced draft cooling tower (wet mechanical draft cooling tower).
    c. Circulating water pipe.
8. Closed cycle cooling water system.
9. Steam generator and auxiliaries:
    a. FD fans.
    b. PA fans.
    c. Air heaters.
    d. Boiler flues and ducts.
    e. Fuel preparation:
        i. Coal crushers.
        ii. Coal silos.
        iii. Coal feeders.
        iv. Coal pulverizers (PC units).
        v. Coal chutes.
    f. Natural gas for startup and low load flame stabilization.
    g. Steam temperature control:
        i. Main steam attemperators.
        ii. Reheat steam attemperators.
    h. Soot blowers.
10. Flue gas flues and ducts.
11. Induced draft fans.
12. Concrete chimney lined with fiberglass reinforced plastic (FRP).
13. Continuous emissions monitoring system (CEMS).
14. Power generation and distribution system:
    a. Generator circuit breaker.
    b. GSU transformer.
    c. Isolated phase bus duct.
    d. Auxiliary transformers.

- e. DC power system.
- f. Uninterruptible power supply.
- g. Power distribution system.

15. Material handling and storage:
    - a. Coal.
    - b. A standard onsite rail loop is included:
        - i. Coal unloading facility.
        - ii. Transfer towers and conveyors.
        - iii. Coal dust suppression system.
    - c. Limestone for use as regent in the PC wet FGD system would be delivered by truck and stored onsite. A reclaim hopper and conveying system from the storage pile to the additive preparation equipment is included.
    - d. Aqueous ammonia handling and storage.
    - e. Byproducts handling and storage system:
        - i. Bottom ash.
        - ii. Economizer ash.
        - iii. Fly ash.
        - iv. Pulverizer rejects.
        - v. FGD byproducts.
16. Water and wastewater treatment systems:
    - a. Water treatment:
        - i. A clarifier pretreatment system.
        - ii. A reverse osmosis and mixed bed demineralizer.
        - iii. Potable water treatment system.
    - b. Wastewater treatment:
        - i. Site sanitary treatment system.
        - ii. Oil water separator
        - iii. Neutralization system
    - c. Steam cycle water chemistry treatment.
    - d. Condensate polisher.
    - e. Ponds:
        - i. Wastewater collection pond.
        - ii. Coal pile runoff pond.
17. Fire protection:
    - a. Water deluge for transformers.
    - b. Hydrant protection for cooling towers.
    - c. Wet pipe sprinkler system in buildings.
    - d. Control room will include fire detection.
    - e. Fire protection pumps with diesel and motor drivers.

18. Field erected tanks will consist of the following:
    a. Service/fire water storage tanks.
    b. Potable water storage tanks.
    c. Condensate tank.
    d. Demineralized water storage tank.
19. Service and control air:
    a. Service/control air compressors.
    b. Desiccant dryers for control air.
20. A diesel-driven generator is included for safe shutdown power.
21. Natural gas fired auxiliary boiler.
22. Electric heat tracing for outdoor water piping.
23. Assumptions for major structures include the following:
    a. Power island building.
    b. Administration/control building.
    c. Plant warehouse maintenance building.
    d. Water treatment buildings.
    e. All buildings would be enclosed and pre-engineered.
    f. Building HVAC (heating, ventilating, and air conditioning) allowance is included.
24. Breeching and structural steel are included in the estimates.
25. Pilings are included under major equipment. Spread footings were assumed for all other foundations. Further stabilization of the existing subgrade is not included.
26. Office furniture, maintenance warehouse bins and shelving, laboratory equipment and furnishings, and machine shop equipment are to be included in the Owner's cost.

Spare parts required for initial operation (startup spares) are included in the equipment purchase contract costs. Operational spare parts are to be included in the Owner's costs.

6.3.2 IGCC

Order of magnitude, overnight EPC capital and total project cost estimates for the IGCC technology option are shown in Table 6-9 below.

Table 6-9 IGCC EPC Capital Cost Estimates, 2013$

CONFIGURATION	2x1 IGCC
Net Plant Output, MW (1)	568
EPC Capital Cost, million$	2,129,000
Unit EPC Capital Cost, $/kW	**3,748**
Owner's Cost Allowance, percentage of EPC Cost	55
Owner's Cost Allowance, $1,000	1,171,000
Total Project Cost, $1,000	3,300,000
Total Project Cost, $/kW	**5,810**

Notes:
1. Based on the estimated thermal performance at average-day ambient conditions and 100 percent load.
2. All EPC capital cost estimates are presented in 2013 dollars. The costs are order of magnitude estimates and, as such, are expected be in the range of ±30 percent of the EPC project cost.
3. EPC capital costs are exclusive of Owner's costs.
4. The sum of the EPC project cost and the Owner's costs will give a total project cost. An Owner's Cost Allowance of 55 percent of the EPC Capital Cost was used.

The information is consistent with recent experience and market conditions, but as demonstrated in recent years, the market is dynamic and unpredictable. Power plant costs will be subject to continued volatility in the future, and the estimates in this report should be considered primarily for comparative purposes.

The following listing provides general EPC capital cost estimating assumptions. The general assumptions identify the scope of supply included in the EPC capital cost estimate. Assumptions related to the development of the performance estimates also apply to the EPC cost estimates. Assumptions related to direct and indirect costs and Owner's costs were provided in Section 2.3. Overall site assumptions were also provided in Section 2.4. Cost estimating assumptions for the IGCC option includes:

1. The focus of IGCC estimate is to provide an EPC cost for a 2x2x1 GE 7F-SG Shell gasifier IGCC.
2. CTGs are GE 7F CTGs fitted with syngas combustors.
3. Two triple pressure reheat HRSGs.
4. The HRSGs do not include duct firing.
5. Two Shell gasifiers with associated downstream syngas trains.
6. ASU for the production of purified oxygen.
7. One condensing STG, 3,600 rpm, tandem-compound, and two-flow (TC2F).
8. Condensate system:

- a. Steam surface condenser--Two-shell, dual pressure, stainless steel tubes.
- b. Condenser vacuum pumps.
- c. Vertical condensate pumps.
- d. HRSG makeup water deaerator.

9. Circulating water system:
    - a. Circulating water pumps.
    - b. Multi-cell, rectangular, fiberglass, mechanical induced draft cooling tower.
    - c. Circulating water pipe.
10. CEMS.
11. Power generation and distribution system:
    - a. CTG circuit breakers.
    - b. STG circuit breaker.
    - c. CTG GSU transformers.
    - d. STG GSU transformers.
    - e. Isolated phase bus duct.
    - f. Auxiliary transformers.
    - g. DC power system.
    - h. Uninterruptible power supply.
    - i. Power distribution system.
12. Material handling and storage:
    - a. Coal:
        - i. A standard onsite rail loop.
        - ii. Coal unloading facility.
        - iii. Transfer towers and conveyors.
        - iv. Coal dust suppression system.
        - v. Coal preparation equipment and silos.
    - b. Byproducts handling and storage system:
        - i. Gasifier slag.
        - ii. Syngas fly ash.
        - iii. Coal preparation rejects.
        - iv. Elemental sulfur.
        - v. Crystallizer byproducts.
13. Water and wastewater treatment systems:
    - a. Water treatment:
        - i. A clarifier pretreatment system.
        - ii. A reverse osmosis and mixed bed demineralizer.
        - iii. Potable water treatment system.
    - b. Wastewater treatment:
        - i. Site sanitary treatment system.
        - ii. Oil water separator

        iii. Neutralization system
    c. Steam cycle water chemistry treatment.
    d. Ponds:
        i. Wastewater collection pond.
        ii. Coal pile runoff pond.

14. Fire protection:
    a. Water deluge for transformers.
    b. Hydrant protection for cooling towers.
    c. Wet pipe sprinkler system in buildings.
    d. Fire detection included in control room.
    e. Fire protection pumps with diesel and motor drivers.
    f. CTG OEM supplied standard CO_2 fire suppression system.
15. Field erected tanks will consist of the following:
    a. Service/fire water storage tanks.
    b. Potable water storage tanks.
    c. Condensate tank.
    d. Demineralized water storage tank.
16. Service and control air:
    a. Service/control air compressors.
    b. Desiccant dryers for control air.
17. A diesel-driven generator is included for safe shutdown power.
18. Electric heat tracing for outdoor water piping.
19. Assumptions for major structures include the following:
    a. Power island building.
    b. Administration/control building.
    c. Plant warehouse maintenance building.
    d. Water treatment buildings.
20. All buildings would be enclosed and pre-engineered.
21. Building HVAC allowance is included.
22. Breeching and structural steel are included in these estimates.
23. Pilings are included under major equipment. Spread footings were assumed for all other foundations. Further stabilization of the existing subgrade is not included.
24. Office furniture, maintenance warehouse bins and shelving, laboratory equipment and furnishings, and machine shop equipment are to be included in the Owner's cost.
25. Spare parts required for initial operation (startup spares) are included in the equipment purchase contract costs. Operational spare parts are to be included in the Owner's costs.

6.4 O&M COSTS

Preliminary order of magnitude estimates of O&M expenses, including fixed and non-fuel variable annual expenses, were developed for each of the USCPC and IGCC technologies. O&M costs are provided in both absolute dollars and on a unitized basis. Unitized fixed costs, those costs that tend to remain fixed and independent of the energy generated by the plant, are provided on a $/kW-yr basis. Unitized variable costs, those costs that are dependent on the energy generated by the plant, are provided on a $/MWh basis. Unitized costs were based on the assumed CF and the estimated thermal performance at hot-day ambient conditions at 100 percent load.

The O&M estimates were derived from other order-of-magnitude estimates developed by Black & Veatch. The O&M costs include labor, materials, maintenance, and overhaul, etc. Assumptions may include labor rates, staffing plans, and cost of consumables. Black & Veatch has utilized Alliant Energy's input in generating O&M cost assumptions as applicable. In the event that assumptions were not readily available from Alliant Energy, Black & Veatch provided assumptions that are reasonable for the project. All O&M estimates were generated on a consistent basis.

6.4.1 USCPC

Assumptions specific to the development of the USCPC O&M cost estimates are provided in Table 6-10. Key O&M consumable costs were based on current market pricing. All assumptions relative to the development of the performance and capital cost estimates presented in previous sections were used in the development of the O&M cost estimates.

Preliminary estimates of O&M expenses for each of the USCPC options are provided in Table 6-11.

Table 6-10 USCPC O&M Operating Assumptions

	UNIT	USCPC
Key O&M Costs, 2013$		
Ash Disposal	$/ton	6.6
Limestone	$/ton	16.4
Lime	$/ton	65.6
Activated Carbon	$/ton	2,400
Ammonia, Aqueous	$/ton	330
Urea	$/ton	345
SCR Catalyst	$/m^3	7,100
Operator Base Salary	$/yr	76,000
Payroll Burden	percent	40
Operating Factors		
Capacity Factor	percent	85
Forced Outage Factor	percent	4.0
Availability Factor	percent	91.2
Service Factor	percent	91.2
Outage Maintenance		
Boiler Outage Duration	weeks	3
Boiler Outage Frequency	yr/outage	1.5 to 3
Turbine Outage Duration	weeks	6
Turbine Outage Frequency	yr/outage	6 to 8

Table 6-11 USCPC Annual O&M Cost Estimates, 2013$

	600 MW USCPC	420 MW USCPC W/CCC
Fixed Costs, $1,000		
Staffing Level	83	100
Labor	9,050	10,904
Routine Maintenance	5,246	8,207
Property taxes & Insurance	Excluded	Excluded
Total Fixed Costs, $1,000	14,295	19,111
Variable Costs, $1,000		
Outage Maintenance (Annualized)		
Turbine/Generator	885	885
Boiler	776	776
Carbon Capture & Compression	N/A	1,246
CO2 transportation & Sequestration	N/A	Excluded
Balance of Unit	846	1,252
Other (including, water, chemicals)	2,757	4,314
Ash and FGD Byproduct Disposal	1,085	1,085
Limestone	383	383
Particulate Removal	1,138	1,138
SCR	2,345	2,345
Carbon Capture Reagents	N/A	1,990
Activated Carbon	5,166	5,166
Total Variable Costs, $1,000	15,380	20,579
Net Plant Output, MW	600	420
Annual Net Generation, MWh	4,467,600	3,127,320
Fixed Costs, $/kW-yr	23.83	45.50
Variable Costs, $/MWh	3.44	6.58

6.4.2 IGCC

Long-term IGCC unit availability is expected to be as high as 85 percent. Commercial IGCC unit availability has been demonstrated to be much lower, primarily during the first several years of operation. Experience gained from coal IGCC plants that have been operating since the mid-1990s will allow new IGCC plants to achieve higher availabilities. Long-term IGCC unit forced outage rates (FORs) are expected to range from 7 to 10 percent. The CTG(s) can operate on backup fuel when syngas is not available. The CC availability with the use of backup fuel is expected to exceed 90 percent. Anticipated availability for the IGCC options is provided in Table 6-12.

Preliminary estimates of O&M expenses for each of the IGCC options are provided in Table 6-13.

Table 6-12 IGCC O&M Operating Assumptions

	2x1 IGCC
Key O&M Costs, 2013$	
Staff, count	126
Operator Base Salary, $/yr	76,000
Labor Burden, percent	40
Operating Factors	
Annual Capacity Factor, percent	82.5
Availability Factor	
IGCC First Year of Operation, percent	40 to 70
IGCC Second Year of Operation, percent	50 to 75
IGCC Third Year of Operation, percent	60 to 80
IGCC After Third Year of Operation, percent	82.5
CC with Backup Fuel, percent	90
Forced Outage Factor, percent	12.5
Note: Operating factors representative of a unit without a hot spare gasifier. Including a hot spare gasifier would improve plant availability on syngas.	

Table 6-13 IGCC Annual O&M Cost Estimates, 2013$

CONFIGURATION	2x1 IGCC
Fixed Operating Cost, $1,000	20,019
Variable Operating Cost, $1,000	26,335
Total Nonfuel O&M Costs, $1,000	46,353
Net Plant Output, MW	568
Annual Net Generation, MWh	4,105,000
Fixed Costs, $/kW-yr	35.24
Variable Costs, $/MWh	6.42
Note: Net plant output and O&M cost estimates based on average day performance.	

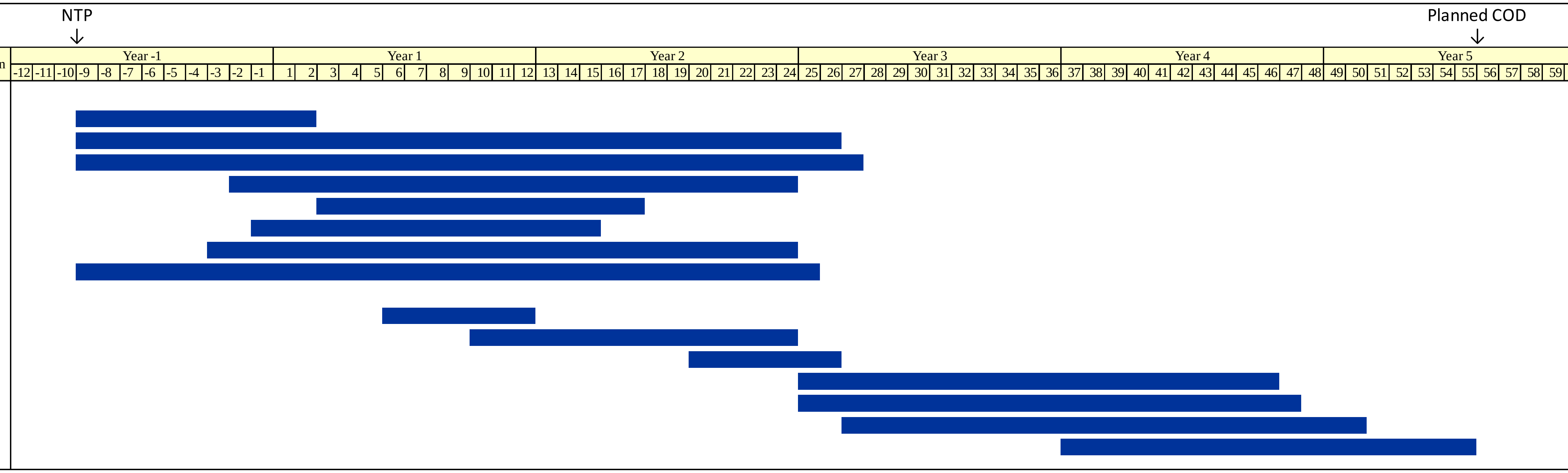
Scheduled maintenance will be performed annually and as needed. Each IGCC train will be shutdown for 2 to 3 weeks annually. The following represents a generic maintenance routine schedule for a typical IGCC plant.

1. CTG: annual inspection, overhaul every 3 years.
2. STG: annual inspection, overhaul every six years.
3. Gasifier Burner: Bi-annual replacement, burners are refurbished.
4. Gasifier: annual inspection, clean and repair as needed.
5. Coal Mill: annual inspection, overhaul every 3 years.
6. Solids (Coal/Slag/Ash) Valves: annual inspection and refurbishment.
7. Coal Feed Aerators/Pickups: annual inspection, repair as needed.
8. Syngas Cooler: annual inspection, repair as needed.
9. Recycle Gas Compressor: annual inspection, repair as needed.
10. Syngas Filter: annual inspection, cleaning and candle replacement as needed.
11. Cyclone and Bag Filters: annual inspection, repair/replace bag filters as needed.
12. Coal and Slag Conveyors: annual inspection, refurbish as needed.
13. Syngas Piping: annual inspection, replace or repair as needed.
14. ASU Cold Box Inspection and Maintenance: every 3 years.
15. ASU Compressor: annual inspection, overhaul every 6 years.

6.5 PRELIMINARY PROJECT SCHEDULE

Preliminary project schedules for the USCPC and IGCC technologies are shown on Figure 6-4 through Figure 6-6. The estimated project durations from notice to proceed (NTP) to planned commercial operation date (COD) are 64 and 76 months for the 600 MW_{net} USCPC and 420 MW_{net} USCPC with carbon capture and compression system, respectively. The estimated project duration for the 600 MW 2x1 IGCC unit is 75 months. As with capital costs, project durations are affected by current market conditions and are subject to change.

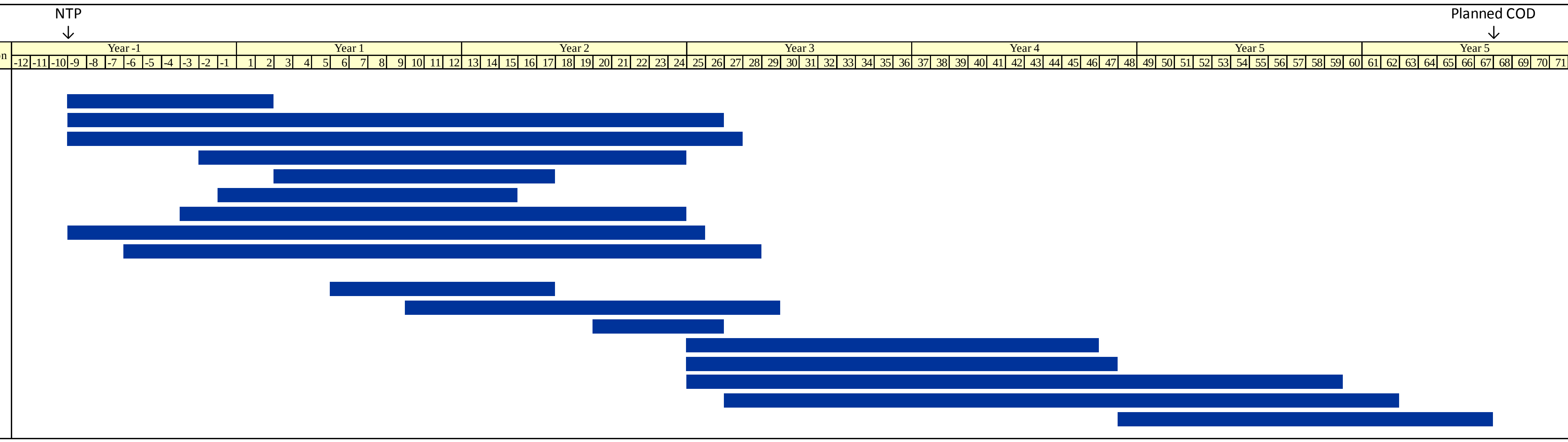
1x0 GE 7F 5-Series	Start	Complete	Duration
Conceptual Design/Equipment Sizing	-9	2	11
Steam Turbine/Generator	-9	26	35
Steam Generator (Boiler)	-9	27	36
Coal Handling	-2	24	26
Steel Design/Detailing	3	17	15
Structural Steel	-1	15	16
Transformers	-3	24	27
AQCS	-9	25	34
Site Preparation	6	12	7
Substructures	10	24	15
Boiler Steel Erection	20	26	7
Boiler Erection to Hydro	25	46	22
Turbine Erection	25	47	23
BOP Mech/Elec Construction	27	50	24
Commissioning	37	55	19



Notes:
1. Schedule assumes permitting is complete at the start of construction.
2. Typical coal plant permitting lasts 24 to 36 months.
3. Site preparation may vary from 3 to 10 months, depending on whether "green" or "pre-developed" site, water table, existing facilities, etc.
4. Specific durations may need to be adjusted depending on where the calendar months fit vs. ordinal months due to weather concerns.
5. This schedule is based on current market conditions and is subject to change.

Figure 6-4 600 MW USCPC Preliminary Project Schedule

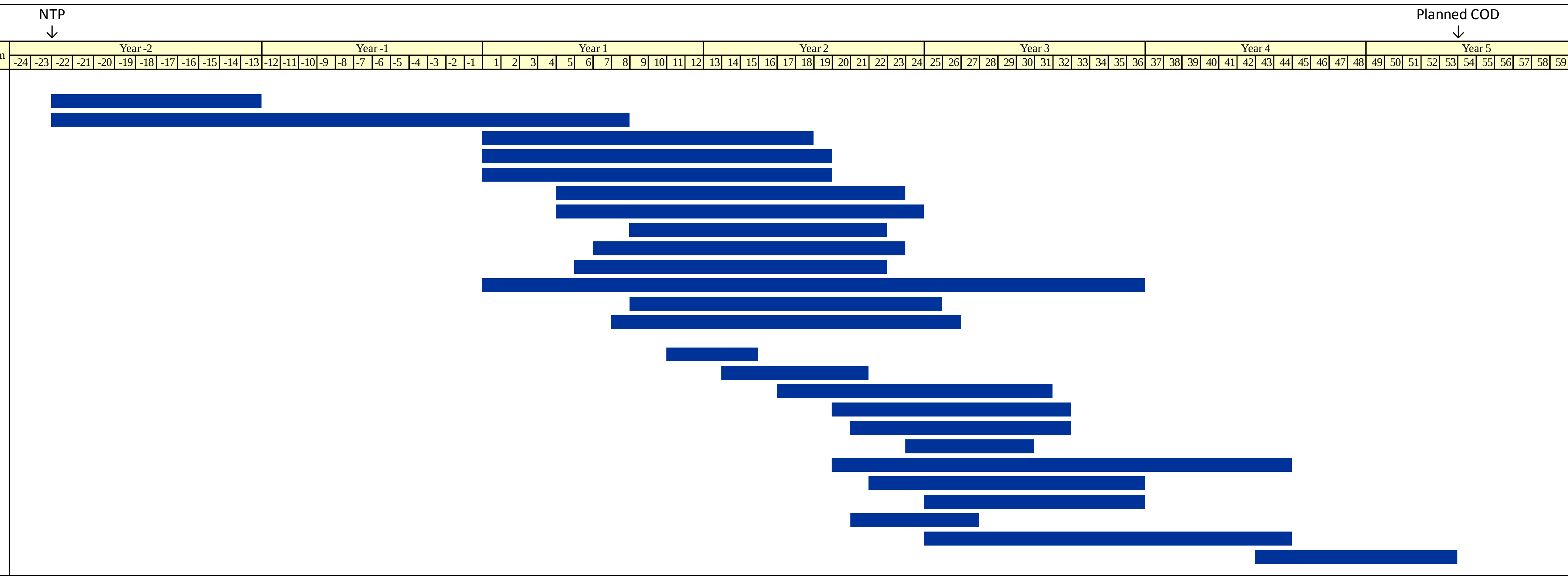
420 MW USCPC w/CCC	Start	Complete	Duration
Conceptual Design/Equipment Sizing	-9	2	11
Steam Turbine/Generator	-9	26	35
Steam Generator (Boiler)	-9	27	36
Coal Handling	-2	24	26
Steel Design/Detailing	3	17	15
Structural Steel	-1	15	16
Transformers	-3	24	27
AQCS	-9	25	34
Carbon Capture and Components	-6	28	34
Site Preparation	6	17	12
Substructures	10	29	20
Boiler Steel Erection	20	26	7
Boiler Erection to Hydro	25	46	22
Turbine Erection	25	47	23
Carbon Capture and Components	25	49	36
BOP Mech/Elec Construction	27	62	36
Commissioning	48	67	20



Notes:
1. Schedule assumes permitting is complete at the start of construction.
2. Typical coal plant permitting lasts 24 to 36 months.
3. Site preparation may vary from 3 to 10 months, depending on whether "green" or "pre-developed" site, water table, existing facilities, etc.
4. Specific durations may need to be adjusted depending on where the calendar months fit vs. ordinal months due to weather concerns.
5. This schedule is based on current market conditions and is subject to change.

Figure 6-5 420 MW USCPC w/ CCC Preliminary Project Schedule

1x0 GE 7F 5-Series	Start	Complete	Duration
Conceptual Plant Design	-22	-13	10
Permitting/Licensing	-22	8	30
CTG	1	18	18
STG	1	19	19
HRSG	1	19	19
Recycle Gas Compressor	5	23	19
Large Heat Exchanger/Vessels	5	24	20
Coal Handling	9	22	14
Air Separation Unit	7	23	17
Transformers	6	22	17
Gasifiers	1	36	36
DCIS	9	25	17
Alloy Pipe	8	26	19
Site Preparation	11	15	5
Substructures and Foundations	14	21	8
CTG/STG Building	17	31	15
HRSG Erection	20	32	13
STG Erection	21	32	12
Coal Gasification Building	24	30	7
Coal Gasification	20	44	25
Coal Handling/Waste Material Handling	22	36	15
Air Separation Unit	25	36	12
Water Treatment	21	27	7
BOP Mechanical/Electrical Construction	25	44	20
Commissioning	43	53	11



Notes:
1. Schedule assumes permitting is complete at the start of construction.
2. Typical coal plant permitting lasts 24 to 36 months.
3. Site preparation may vary from 3 to 10 months, depending on whether "green" or "pre-developed" site, water table, existing facilities, etc.
4. Specific durations may need to be adjusted depending on where the calendar months fit vs. ordinal months due to weather concerns.
5. This schedule is based on current market conditions and is subject to change.

Figure 6-6 **600 MW IGCC Preliminary Project Schedule**

6.6 PRELIMINARY CASH FLOW

Preliminary cash flow summaries for the USCPC and IGCC technologies are provided in Table 6-14 and Table 6-15. The cash flow summaries are also depicted graphically on Figure 6-7 through Figure 6-9. The estimates include incremental and cumulative cash flows and are shown as a percent of total capital cost versus time. The cash flow summaries were based on the project schedules described in the previous section.

Table 6-14 Preliminary USCPC Cash Flow Estimates

MONTH	600 MW USCPC		420 MW USCPC W/ CCC	
	INCREMENTAL	CUMULATIVE	INCREMENTAL	CUMULATIVE
-9	2.0	2.0	1.2	1.2
-8	2.0	4.0	1.2	2.4
-7	0.5	4.5	1.2	3.7
-6	0.5	5.0	1.1	4.7
-5	0.8	5.8	0.6	5.3
-4	0.8	6.5	0.6	5.9
-3	0.8	7.3	0.6	6.5
-2	0.8	8.0	0.6	7.1
-1	1.0	9.0	0.7	7.8
1	1.0	10.0	0.7	8.6
2	1.0	11.0	0.7	9.3
3	1.0	12.0	0.9	10.2
4	1.8	13.8	1.0	11.2
5	1.8	15.5	1.0	12.2
6	1.8	17.3	1.0	13.2
7	1.8	19.0	1.4	14.6
8	1.8	20.8	1.5	16.1
9	1.8	22.5	1.5	17.5
10	2.3	24.8	1.5	19.0
11	2.3	27.0	1.6	20.6
12	2.5	29.5	1.6	22.3
13	2.5	32.0	1.6	23.9
14	3.0	35.0	1.8	25.7
15	3.0	38.0	2.1	27.8
16	3.0	41.0	2.1	29.9
17	3.0	44.0	2.1	32.1
18	3.5	47.5	2.3	34.4
19	3.5	51.0	2.5	36.8
20	3.5	54.5	2.5	39.3
21	3.5	58.0	2.5	41.8
22	3.8	61.8	2.7	44.5
23	3.8	65.5	2.9	47.4
24	3.8	69.3	2.9	50.3
25	3.8	73.0	2.9	53.2
26	3.3	76.3	3.0	56.3

MONTH	600 MW USCPC		420 MW USCPC W/ CCC	
	INCREMENTAL	CUMULATIVE	INCREMENTAL	CUMULATIVE
27	3.3	79.5	3.1	59.3
28	2.3	81.8	3.1	62.4
29	2.3	84.0	3.1	65.5
30	1.5	85.5	3.0	68.5
31	1.5	87.0	3.0	71.4
32	1.5	88.5	3.0	74.4
33	1.5	90.0	2.7	77.1
34	1.0	91.0	2.2	79.2
35	1.0	92.0	2.1	81.3
36	1.0	93.0	2.1	83.4
37	1.0	94.0	1.7	85.1
38	0.5	94.5	1.2	86.3
39	0.5	95.0	1.2	87.5
40	0.5	95.5	1.2	88.7
41	0.5	96.0	1.1	89.8
42	0.5	96.5	0.9	90.7
43	0.5	97.0	0.9	91.7
44	0.5	97.5	0.9	92.6
45	0.5	98.0	0.7	93.3
46	0.5	98.5	0.6	93.8
47	0.5	99.0	0.6	94.4
48	0.1	99.1	0.5	95.0
49	0.1	99.3	0.5	95.4
50	0.1	99.4	0.4	95.8
51	0.1	99.5	0.4	96.3
52	0.1	99.6	0.4	96.7
53	0.1	99.8	0.4	97.1
54	0.1	99.9	0.4	97.5
55	0.1	100.0	0.4	97.9
56	--	--	0.4	98.3
57	--	--	0.3	98.6
58	--	--	0.3	98.8
59	--	--	0.3	99.1
60	--	--	0.2	99.3
61	--	--	0.1	99.4
62	--	--	0.1	99.5

MONTH	600 MW USCPC		420 MW USCPC W/ CCC	
	INCREMENTAL	CUMULATIVE	INCREMENTAL	CUMULATIVE
63	--	--	0.1	99.6
64	--	--	0.1	99.7
65	--	--	0.1	99.8
66	--	--	0.1	99.9
67	--	--	0.1	100.0

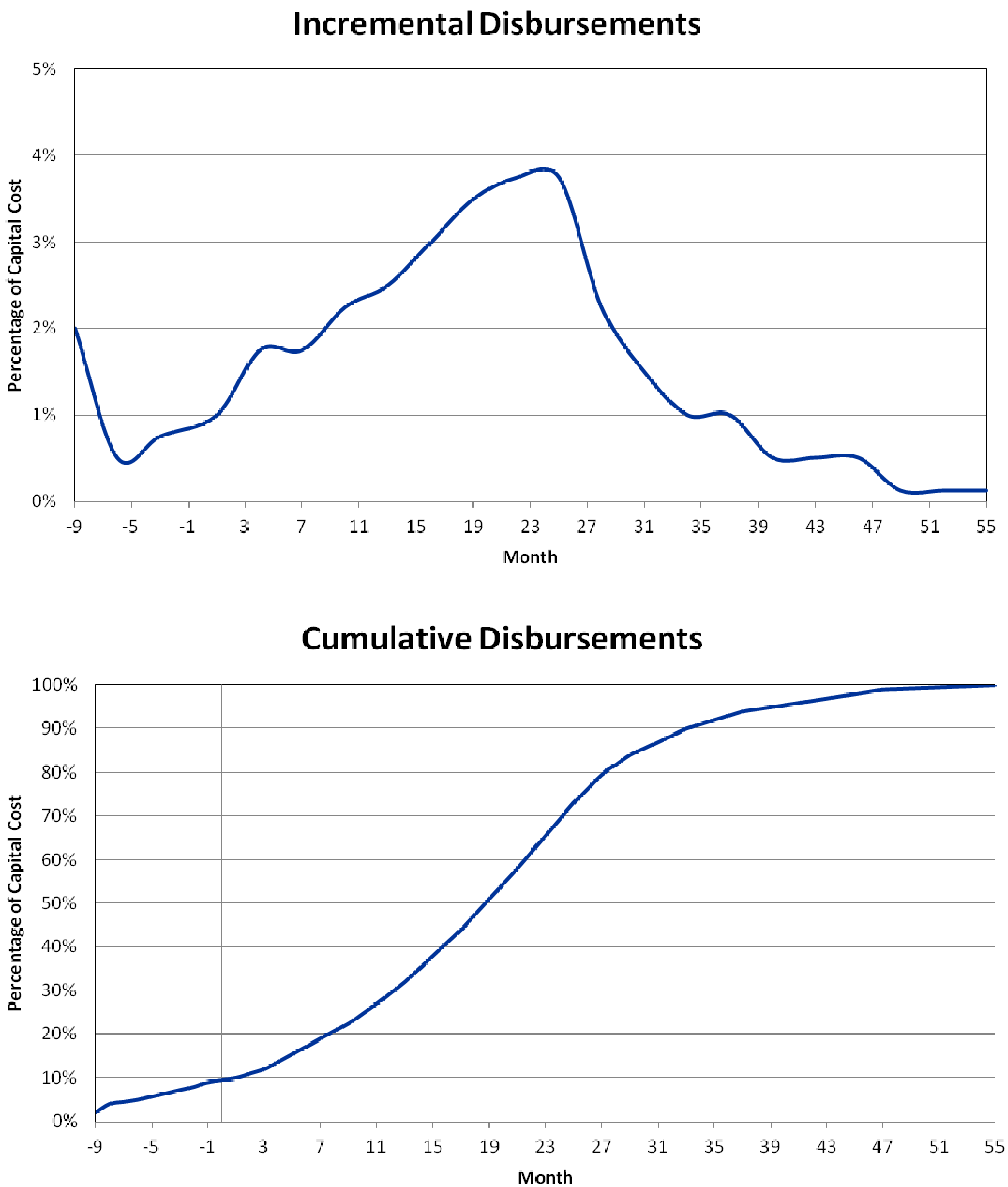
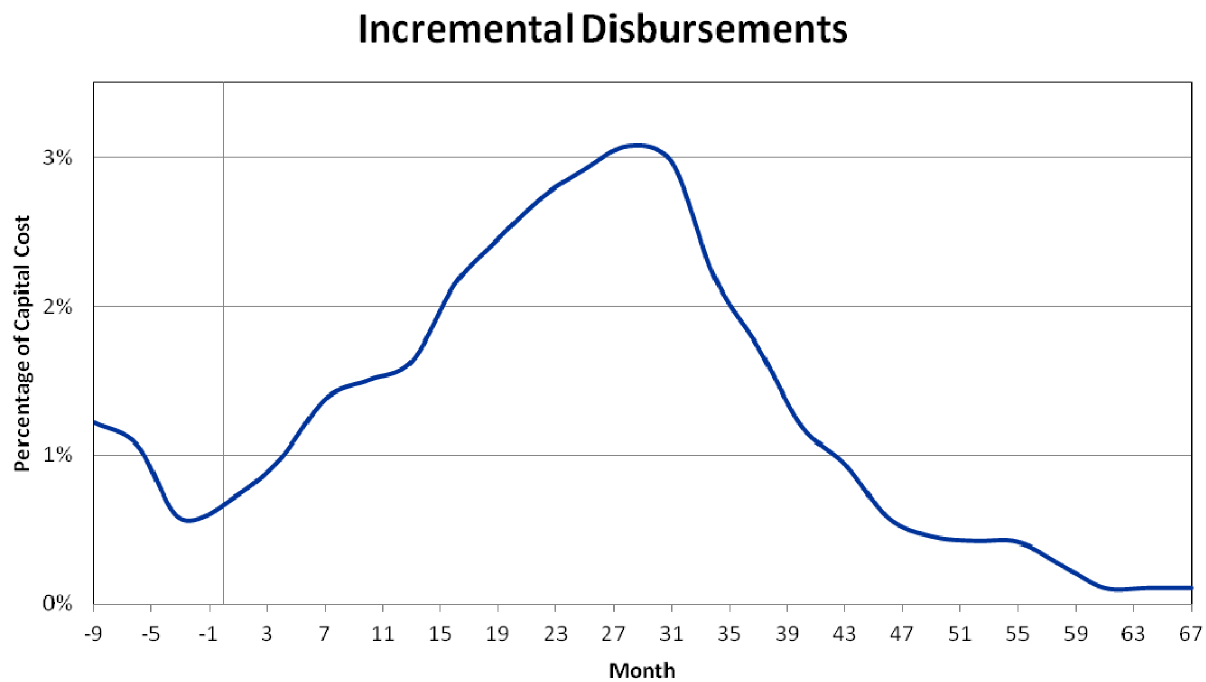


Figure 6-7 600 MW USCPC Cash Flow Curves



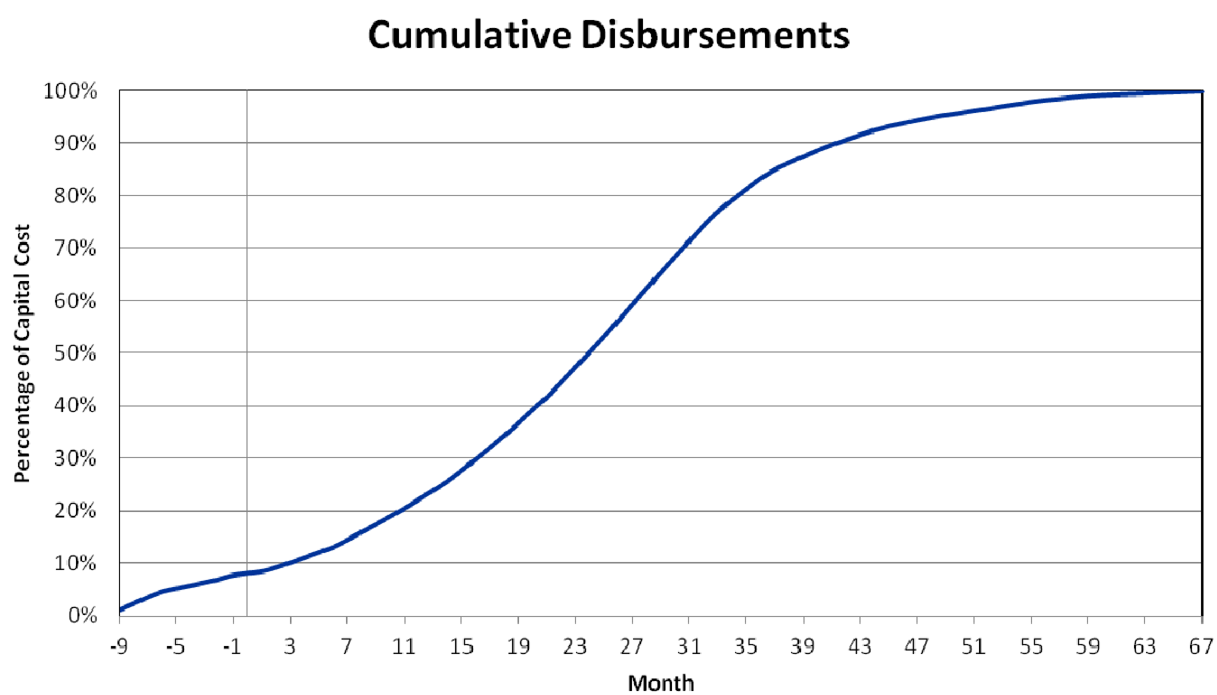
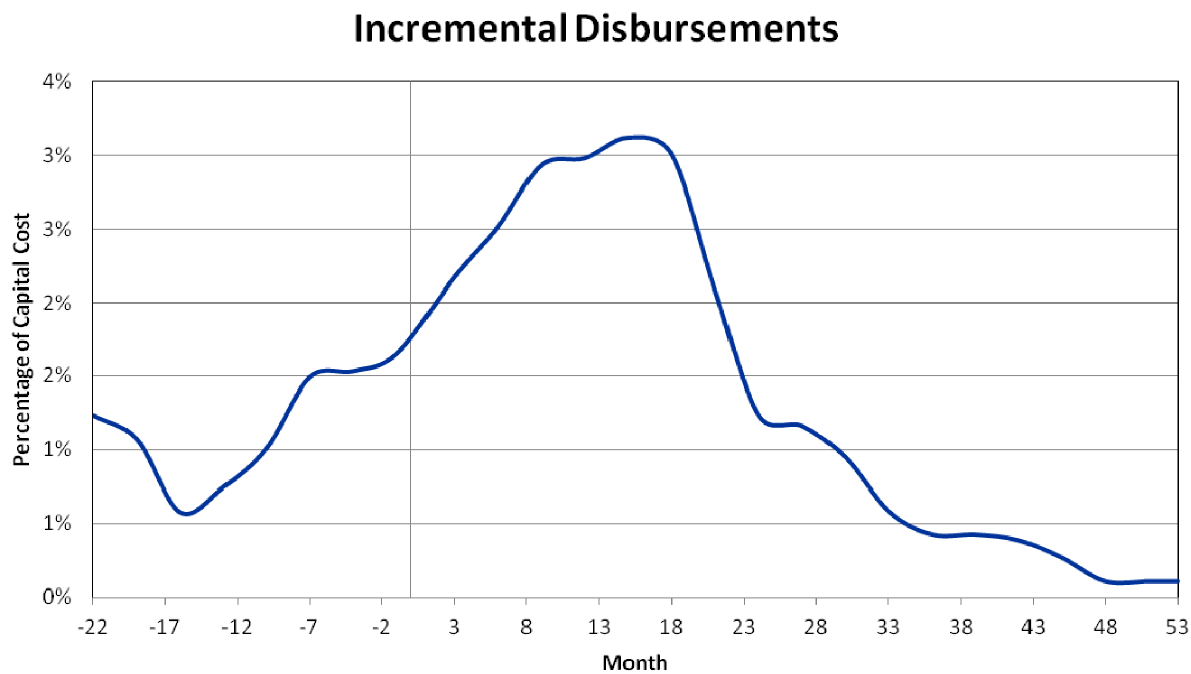


Figure 6-8 420 MW USCPC w/ CCC Cash Flow Curves

Table 6-15 Preliminary IGCC Cash Flow Estimates

MONTH	2x1 IGCC INCREMENTAL	2x1 IGCC CUMULATIVE
-22	1.2	1.2
-21	1.2	2.5
-20	1.2	3.7
-19	1.1	4.8
-18	0.6	5.4
-17	0.6	5.9
-16	0.6	6.5
-15	0.7	7.2
-14	0.7	7.9
-13	0.7	8.7
-12	0.7	9.4
-11	0.9	10.4
-10	1.0	11.4
-9	1.0	12.4
-8	1.0	13.4
-7	1.5	14.9
-6	1.5	16.4
-5	1.5	17.9
-4	1.5	19.4
-3	1.7	21.1
-2	1.7	22.7
-1	1.7	24.4
1	1.9	26.3
2	2.2	28.5
3	2.2	30.6
4	2.2	32.8
5	2.4	35.3
6	2.5	37.8
7	2.5	40.3
8	2.5	42.8
9	2.9	45.7
10	2.9	48.7
11	2.9	51.6
12	3.0	54.6
13	3.1	57.7
14	3.1	60.8
15	3.1	63.9
16	3.1	67.0

MONTH	2x1 IGCC	
	INCREMENTAL	CUMULATIVE
17	3.0	70.0
18	3.0	73.0
19	3.0	76.0
20	2.3	78.3
21	2.1	80.4
22	2.1	82.5
23	2.1	84.6
24	1.2	85.8
25	1.2	87.1
26	1.2	88.3
27	1.2	89.5
28	1.0	90.4
29	1.0	91.4
30	1.0	92.3
31	0.8	93.1
32	0.6	93.7
33	0.6	94.3
34	0.6	94.9
35	0.5	95.3
36	0.4	95.7
37	0.4	96.2
38	0.4	96.6
39	0.4	97.0
40	0.4	97.5
41	0.4	97.9
42	0.4	98.3
43	0.3	98.5
44	0.3	98.8
45	0.3	99.1
46	0.2	99.3
47	0.1	99.4
48	0.1	99.5
49	0.1	99.6
50	0.1	99.7
51	0.1	99.8
52	0.1	99.9
53	0.1	100.0



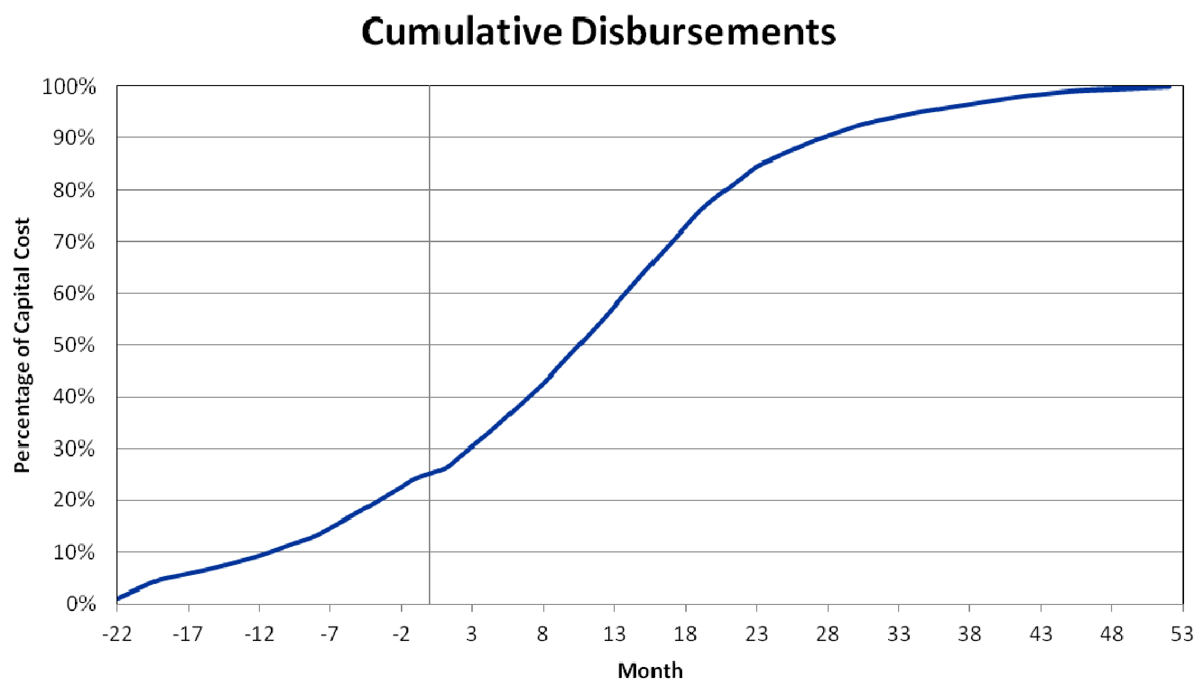


Figure 6-9 2x1 IGCC Cash Flow Curve

7.0 Nuclear Options

This section includes technology descriptions, performance and emissions, and cost characteristics for the following nuclear technology options:

- Single Unit Westinghouse Advanced Passive 1000 (AP1000).
- Small Modular Reactor (SMR).

The following characteristics are addressed for the option above:

- Summary level technology descriptions.
- Thermal performance estimates including net plant capacity and net plant heat rate.
- The following cost estimates are provided in 2013$:
  - Order of magnitude overnight capital cost estimates.
  - Fixed O&M.
  - Variable O&M.
- Typical high-level refueling and outage maintenance schedules.
- Preliminary project schedule and project durations.
- Cash flow summary.
- Fuel cost and sourcing consisting of discussions regarding raw uranium, separation, enrichment, and fabrication (fuel cost provided on $/MWh and $/MBtu basis).
- Discussion regarding licensing requirements.
- Discussion regarding spent fuel and reprocessing and low level radioactive waste disposal.
- Discussion on decommissioning requirements and costs.

7.1 TECHNOLOGY DESCRIPTIONS

The following subsections contain brief general descriptions of power plant key systems, which were the basis of estimates for performance, capital costs, O&M costs, construction schedules, and cash flows.

7.1.1 Pressurized Water Reactors

Pressurized water reactors (PWRs) are a class of nuclear reactors that maintain an HP primary loop (a.k.a. reactor coolant system) that transfers heat to the secondary steam cycle, while preventing the primary loop from boiling. The PWR design represents approximately 60 percent of the currently operating US domestic fleet.

The nuclear reactor units will burn enriched uranium (<5 wt percent) delivered to the site every 18 or 24 month refueling cycle. With each refueling outage, one third of the core (approximately 52 assemblies) is replaced.

The AP1000 is a two-loop 1,200 electric (MWe) gross output PWR with passive safety features that incorporates extensive simplification concepts. The reactor coolant system (RCS), or primary system, consists of two heat transfer loops, each with a steam generator, two canned-type

7,000 hp reactor coolant pumps, a single hot leg, and two cold legs (for circulating light water coolant/moderator).

The AP1000 safety systems maximize the use of natural driving forces such as pressurized gas, gravity flow, and natural circulation flow. The safety systems do not use active components (such as pumps, fans, or diesel generators) and are designed to function without safety-grade support systems (such as AC power, component cooling water, service water, or HVAC).

The AP1000 steam generators are vertical U-tube design, recirculating, shell and tube heat exchangers with triangular pitch tube arrangements and integral moisture separation equipment. The reactor coolant pumps are directly attached to the bottom of the steam generators. The steam generator removes heat from the reactor coolant system while retaining radioactive contaminants in the primary system. Steam is generated on the shell side, flows upward through the two-stage moisture separators (swirl vane and chevrons), and exits through the outlet nozzle at the top of the vessel. The two steam lines are routed separately to the inlet of the HP turbine.

The steam generated in the two steam generators is supplied to the HP turbine section of the tandem-compound, six-flow STG. After expansion through the HP turbine, the steam passes through two moisture separator reheaters (MSRs) and is admitted to the three LP turbines. Exhaust steam is condensed and deaerated in the main condenser. The condenser is cooled by the circulating water system (CWS). The motor-driven condensate pumps draw suction from the hotwell and deliver the condensate through four stages of LP feedwater heaters (three parallel trains) to the fifth deaerating heater. The motor-driven feedwater booster and feedwater pumps deliver the feedwater through one stage of HP heaters (two parallel trains) to the steam generators.

The main turbine-generator is a 1,800 rpm, tandem-compound, six-flow, reheat unit with 54 inch last stage blades (TC6F 54 inch LSB). The HP turbine element includes one double-flow, HP turbine. The LP turbine elements include three double-flow, LP turbines and two external MSRs with two stages of reheating. The single direct-driven generator is water cooled and rated at 1,375 MVA at 0.90 power factor (PF). Other related system components include a complete turbine generator lubrication oil system, a digital electrohydraulic (DEH) control system with supervisory instrumentation, a turbine steam sealing system, overspeed protective devices, turning gear, a stator cooling water system, a generator hydrogen and seal oil system, a generator CO_2 system, an exciter cooler, a rectifier section, an exciter, and a voltage regulator.

The plant heat rejection system includes a surface condenser, wet mechanical draft cooling tower, circulating water pumps, and auxiliary cooling water heat exchangers.

The AQCS would comply with applicable federal and state emissions requirements for HAPs and with US Nuclear Regulatory Commission (US NRC) requirements for radiological emissions. NO_x emissions would be controlled by limiting the number of annual fired hours for the auxiliary boiler and diesel generators.

Water for use at the plant is assumed to be surface water that is available at the plant boundary. The water is used for circulating water, potable water, fire water, lime hydration for the dry scrubber, steam cycle makeup, and other general services.

Pretreatment of the raw water is assumed to be required for circulating water makeup and other plant uses. The pretreated water is then chlorinated for service water and potable uses and treated by demineralization for use as steam cycle makeup.

A condensate polishing system with a capacity of one-third design condensate flow is provided to remove corrosion products and ionic contaminants. The AP1000 employs an all-volatile (AVT) method to minimize general corrosion in the feedwater system, steam generators, and main steam piping. A pH adjustment chemical and an oxygen scavenger are the two chemicals injected in the condensate pump discharge, downstream of the condensate polishers.

The plant will also include a packaged boiler system, which provides auxiliary steam for startup and building heating during outages. The auxiliary boiler is fueled with No. 2 oil (American Society for Testing and Materials [ASTM] D975), with minimum onsite storage of 7 days. The auxiliary boiler is operated 30 days per year to maintain availability.

For non-nuclear safety-related purposes, the plant will also include two 4,000 kW standby diesel generators, and two 35 kW ancillary diesel generators. The diesel generators are fueled with No. 2 oil (ASTM D975), with minimum onsite storage of 7 days. The diesel generators are operated 4 hours each month to maintain availability.

7.1.2 Small Modular Reactors

Conventional reactors, such as the Westinghouse AP1000, MHI US-APWR, or the Toshiba Advanced Boiling Water Reactor (ABWR), provide electric power producers with a large, reliable baseload power generation technology that has low emissions and zero CO_2 production. However, these reactors are only available in configurations with capacities above 1,000 megawatt (MW). In addition, these technologies are more often considered in a "twin" unit arrangement that can result in a lower unitized cost because of shared BOP equipment. Installing twin reactors requires integration into a large interconnected system with large baseload electric demand, and a large capital investment.

An alternative to the large reactors would be a smaller one that would allow smaller utilities to take advantage of some of the favorable characteristics provided by a nuclear technology. The concept of small nuclear reactors is not new. Nuclear power generation was established in the 1950s. Early reactors were initially considered small, approximately 100 MW. Navies have been utilizing small reactors, up to 200 MW, for decades to power some larger sea-going vessels. Another example of nuclear power use is the four 62 megawatt, thermal (MWth) small reactors that have been operating at the Bilibino cogeneration facility located in Siberia since 1976. These reactors provide district heating and electric power and, according to the World Nuclear Association, they have been doing so at the remote location at a cost that would be competitive with alternative fossil technologies.

Multiple technology vendors are now developing a new generation of SMRs that may give more power producers the opportunity to utilize a nuclear power generation technology. Vendors are currently developing SMR options that vary in capacity that fall within a class of a 25 to 300 MW. The International Atomic Energy Agency (IAEA) has defined a "small" reactor as one that produces less than 300 MW. Reactors between 300 and 700 MW are classified as "medium" reactors. Because of their modularity, SMRs may provide a benefit to producers by allowing them to install smaller increments of planned capacity based on forecasted requirements and to arrange multiple SMRs to meet a capacity need.

Multiple SMR projects exist throughout the world. In 2012, the DOE called for applications from industry to support the development of one or two US light-water reactor designs. Westinghouse, Babcock & Wilcox (B&W), Holtec, and NuScale Power applied with units ranging from 45 MW to 225 MW. In November 2012, the DOE announced its decision to support B&W up to $226 million, with B&W matching at least this amount. In March 2013, the DOE requested second-round funding applications. Proposals were made by Westinghouse, Holtec, NuScale, General Atomics, and Hybrid Power Technologies. According to the World Nuclear Association, an SMR project in China referred to as the HTR-PM project has a project status further along than any other SMR project.[8] This project utilizes two 250 MWth reactors and will have an electrical output of 210 MW.

In September 2012, IAEA stated that 131 SMRs operating in 26 different countries, and produced a total installed capacity of 59 GWe.[9] The presentation identified 14 SMRs currently under construction in six countries: Argentina, China, India, Pakistan, the Russian Federation, and Slovakia. Additionally, research is being conducted in ten countries on approximately 45 Advanced SMR concepts for "electricity generation, process heat production, desalination, hydrogen generation, and other applications."[10]

Table 7-1 identifies the leading SMR technologies. Multiple SMR technology vendors are US-based or are planning on applying for US Nuclear Regulatory Commission (NRC) design certification (DC) to be able to offer their technology within the United States.

Table 7-1 Developing New Generation SMR Projects

PROJECT NAME	PROJECT CAPACITY	TYPE	DEVELOPER
Westinghouse SMR	200 MWe	PWR	Westinghouse, USA
mPower	125 MWe	PWR	Babcock & Wilcox, USA
NuScale	45 MWe	PWR	NuScale Power, USA

Note:
1. PWR = Pressurized Water Reactor
2. Source: Referenced from World Nuclear Association.

[8] World Nuclear Association, Small Nuclear Power Reactors, Retrieved July 2013 at: http://www.world-nuclear.org/info/Nuclear-Fuel-Cycle/Power-Reactors/Small-Nuclear-Power-Reactors/

[9] Status of Small and Medium Sized Reactor Designs, International Atomic Energy Agency, retrieved July 2013 at: http://www.iaea.org/NuclearPower/Downloadable/SMR/files/smr-status-sep-2012.pdf

[10] Small and Medium Sized Reactors Development, Assessment, and Deployment, IAEA retrieved July 2013 at: http://www.iaea.org/NuclearPower/SMR/

7.1.2.1 Summary Level Technology Descriptions

The following sections provide summary level technology descriptions for B&W mPower and NuScale SMR technologies.

Babcock & Wilcox mPower

B&W first announced the mPower SMR in 2009. The mPower is an Advanced Light Water Reactor (ALWR), Pressurized Water Reactor (PWR) in which the nuclear reactor and steam generator are contained within a single vessel, a Nuclear Steam Supply System (NSSS). Compared to traditional larger PWR NSSS, the mPower NSSS is greatly simplified. A traditional PWR consists of a pressurizer and steam generator within their own pressure vessel. These components are connected by a large primary system and large reactor cooling pumps. These structures are substantially larger than the mPower technology, and they must be field-constructed. According to B&W, no onsite construction would be required with an mPower NSSS.

With the mPower technology, there are no large piping penetrations to the NSSS. The entire primary system is integral to a single unit NSSS, which eliminates the risk of a large break loss-of-coolant accident (LOCA). The only pipes that connect to the NSSS are the secondary side, the feedwater, and the steam, which has no connections to the primary side inside the NSSS. There is also a clean-up line and an emergency injection line, all of which are fairly small penetrations.[11]

Refueling the mPower reactor is completed by removing the entire core, as opposed to pulling individual fuel assemblies.[4] In a traditional PWR, fuel assemblies are repositioned within the core over their useful life. The mPower was designed so fuel assemblies do not need to be repositioned inside the reactor core over the expected 4 year life of the fuel. Therefore, the refueling cycle is stretched to more than 4 years, compared to a traditional PWR, which may have an 18 month refueling cycle. The mPower core contains 69 fuel assemblies that are approximately half the length of standard fuel assemblies found in a PWR reactor.[4]

The mPower reactor has a nominal capacity to support 125 megawatt electric (MWe) standard PWR fuel. It is intended for the reactor to be modular to allow scalability of a plant from 1 to more than 10 units. The mPower reactor is designed to be factory-assembled and delivered to the site as a ready-to-be-installed reactor. Standard design is for the NSSS to be installed below ground. The following are some of the beneficial characteristics of the mPower reactor, as reported by B&W[12]:

- North American shop-manufactured.
- Rail shippable NSSS.
- No onsite NSSS construction.
- Steam generator integral to the NSSS.
- Passive safety systems and secured underground containment.
- No need for safety grade backup power, natural convective cooling capability.
- Three year construction cycle.

[11] Generation mPower website, accessed July 2013 at: http://www.generationmpower.com/
[12] B&W mPower Brochure, retrieved July 2013 at: http://www.babcock.com/library/pdf/E2011002.pdf

- Conventional core and standard five percent enriched PWR fuel.
- More than 4 year operating cycle between refueling.
- Used fuel stored in a spent fuel pool for the life of the reactor.
- Sixty year plant life.
- Sequential partial plant outages.
- Standardized BOP.
- Multi-unit (1 to more than 10) plant.

Figure 7-1 through Figure 7-3 provides conceptual drawings of a nuclear power plant utilizing B&W's mPower SMR technology. The depicted plant shows two mPower reactors that would have a plant output of 250 MWe (2x125 MWe). A benefit of SMRs is that they can be arranged in a multiple reactor configuration to provide scalable project capacity.

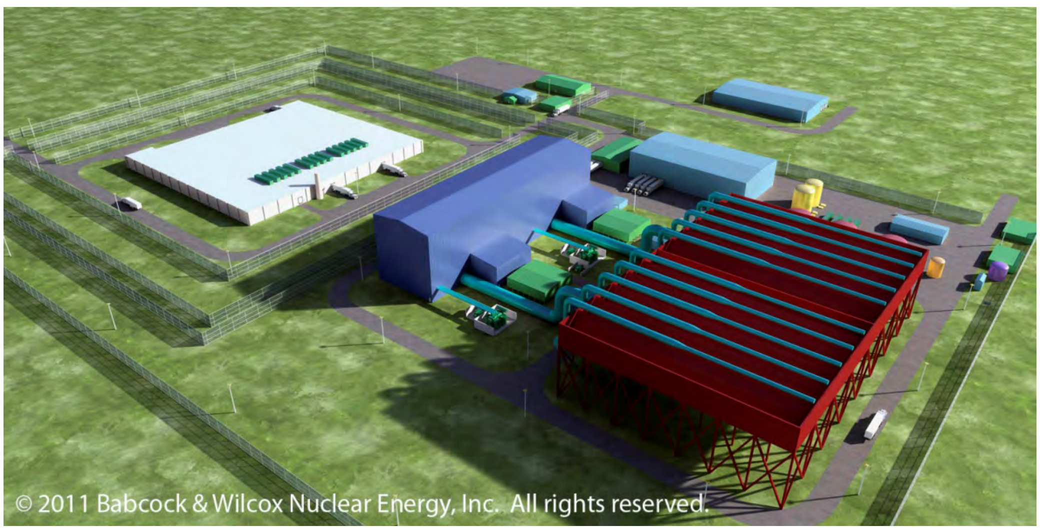


Figure 7-1 Conceptual Plant Drawing of Two 125 MW mPower Reactors

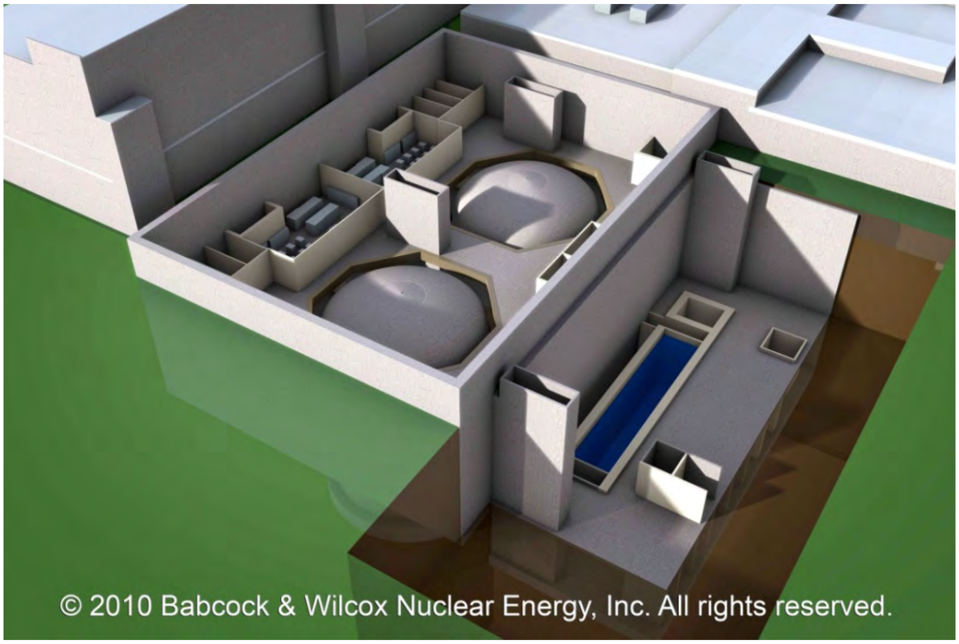


Figure 7-2 Conceptual Plant Drawing of Two 125 MW mPower Reactors

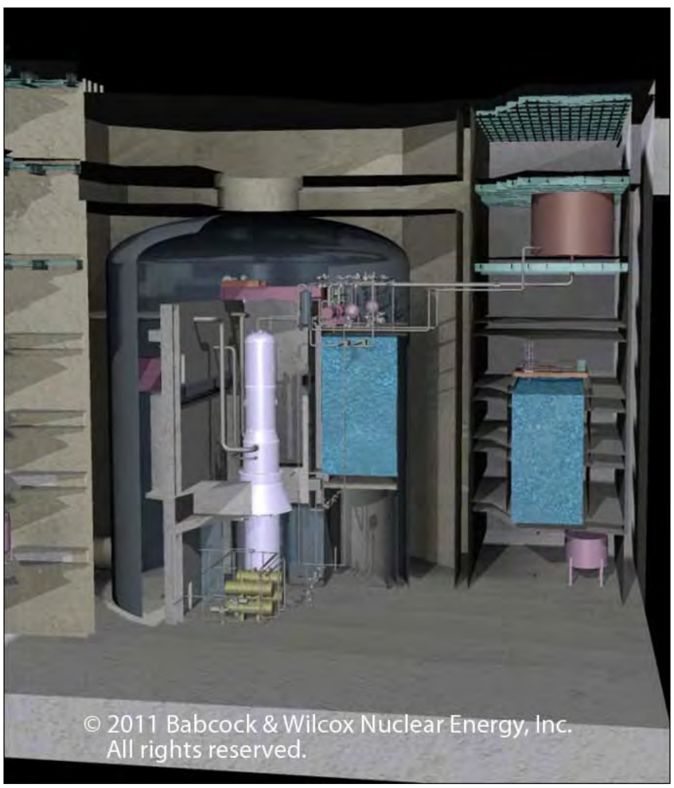


Figure 7-3 Conceptual Drawing of a Single mPower Reactor Module

NuScale

NuScale technology stems from research conducted by the Idaho National Engineering and Environment Laboratory (INEEL) and Oregon State University (OSU). The research began in 2000 and was funded by a US Department of Energy (DOE) grant. The DOE study was concluded in 2003; however, the research continued at OSU until 2007, when NuScale was granted exclusive rights to the technology through a technology transfer program.[13]

The NuScale technology is an ALWR, PWR that is scalable and has an output of 45 MWe. Much like the mPower technology, the NuScale technology is modular and has a completely contained singular NSSS that is shop-manufactured and delivered to the site for installation. The reactor and steam generator are all integral and self-contained within a steel containment vessel, the NSSS. Dimensions of the NuScale NSSS are reported to be 65 feet long, with a diameter of 15 feet.[14] This size would allow the NuScale NSSS to be shipped by standard rail. The entire primary system is integral to a single unit NSSS, which eliminates the risk of a large break LOCA. The only major piping systems connected to the NSSS are those on the secondary side, which supplies steam to the steam turbine generator. Standard design is for the NSSS to be installed below ground. NuScale has also incorporated several features that address post 9/11 safety threats.[15]

In the NSSS, natural convention circulation is used to circulate cooling water and cool the reactor. No motor-operated pumps are required, and there are no pumps on the reactor system that require an emergency electrical power to cool the reactor if power were to be lost at the site.[8]

The NuScale reactor utilizes fuel common to current operating nuclear power plants. Each reactor assembly contains 17 rows, and each row contains 17 fuel rod assemblies. The refueling cycle is 24 months.[16]

The following provides an overview process description of the NuScale technology referenced from their website. Please refer to the NuScale Process Diagram provided in Figure 7-4 with the following process description.[9]

The reactor pressure vessel (1) measures 65 x 9 feet. It sits within a containment vessel (2). The integrated reactor and containment vessel operate inside a water-filled pool (3) that is built below grade.

The NuScale reactor operates using the principles of natural circulation. No pumps are needed to circulate water through the reactor. Instead, the system uses a convection process. Water is heated as it passes over the fuel or core (4).

[13] History of the NuScale Power Technology, retrieved July 2013 at: http://www.nuscalepower.com/history.aspx
[14] Benefits of NuScale's Technology, NuScale Website, retrieved July 2013 at: http://www.nuscalepower.com/nuscalesmrbenefits.aspx
[15] Security built into every NuScale Plant, NuScale Website, retrieved July 2013 at: http://www.nuscalepower.com/secure.aspx
[16] How NuScale Technology Works, NuScale Website, retrieved June 2011 at: http://www.nuscalepower.com/ot-How-NuScale-Technology-Works.php

As it is heated, the water rises within the interior of the vessel. After the heated water reaches the top of the riser (5), it is drawn downward by water that has been cooled passing through the steam generators (6). The cooler water has a higher density. It is pulled by gravity back down to the bottom of the reactor, where it is again drawn over the core.

Water in the reactor system and the steam generator system are kept separate. As the hot water in the reactor system passes over the hundreds of tubes in the steam generators, heat is transferred through the tube walls.

The water inside the tubes turns into steam. The steam turns turbines (7), which are attached by a single shaft to the electrical generator. (Note: number (8) was omitted from the figure.)

After passing through the turbines, the steam loses its energy. It is cooled back into liquid form in the condenser (9) and then pumped by the feedwater pump (10) back to the steam generator (6), where it begins the cycle again.

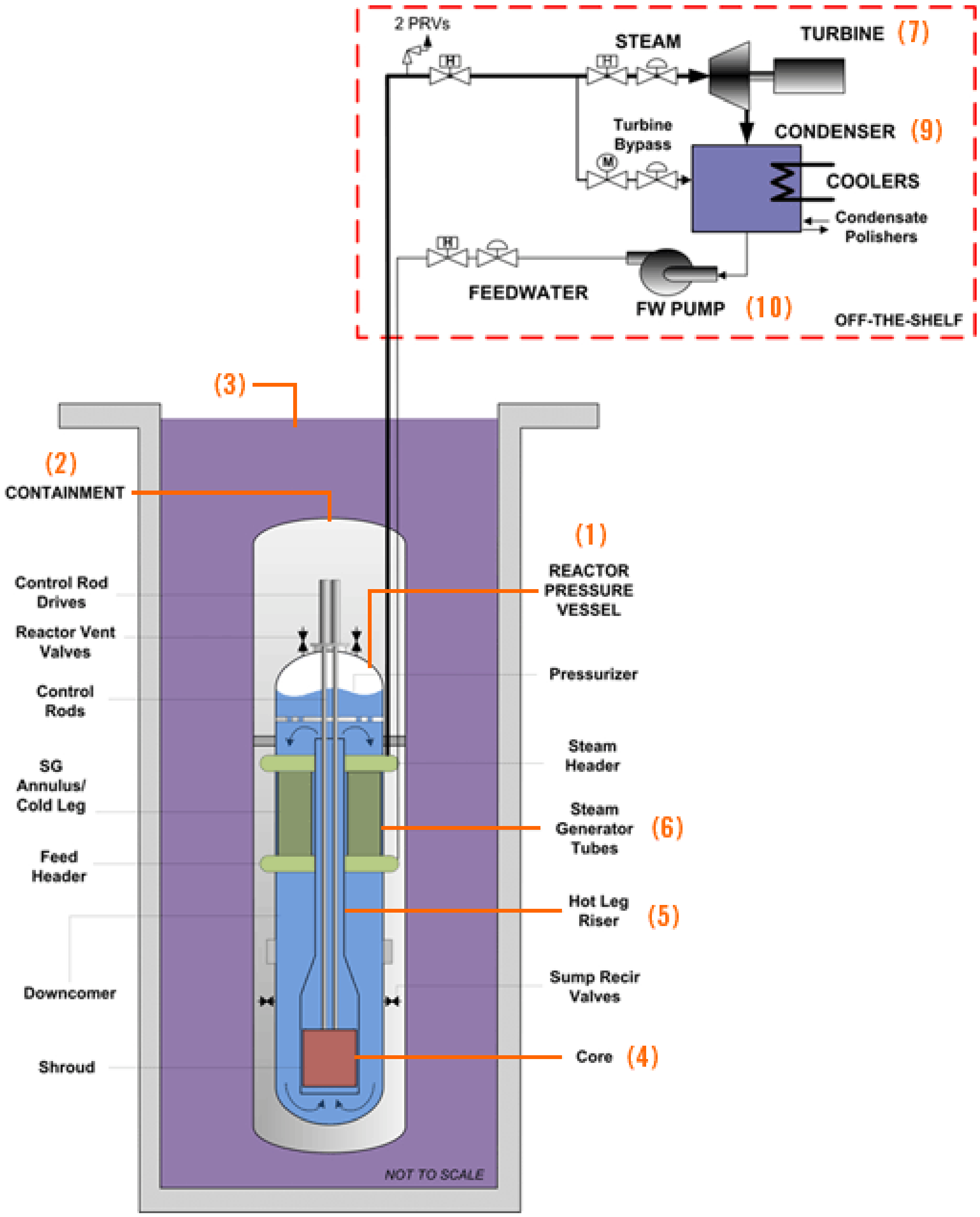


Figure 7-4 NuScale Process Diagram

Figure 7-5 through Figure 7-7 provides conceptual drawings of a nuclear power plant utilizing NuScale's technology. A benefit of SMRs is that they can be arranged in a multiple reactor configuration to provide scalable project capacity.

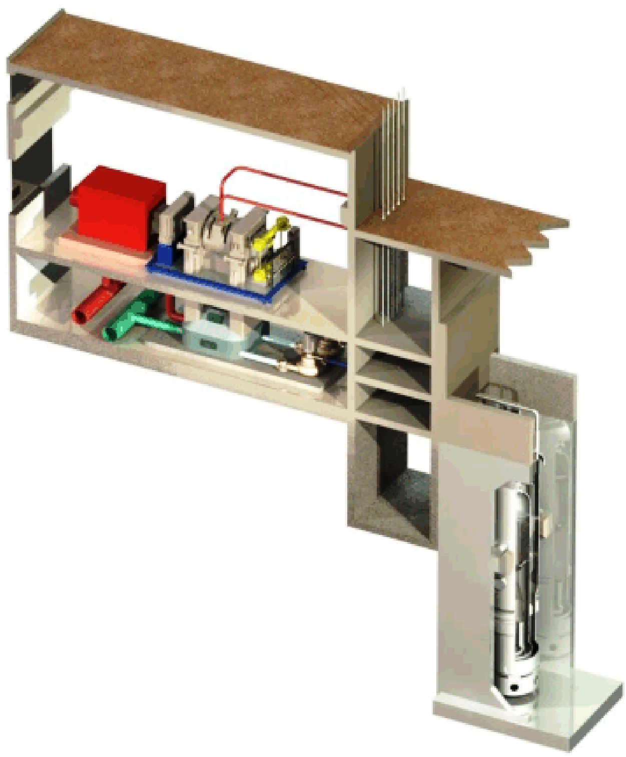


Figure 7-5 Single-Unit Side View of the NuScale System Design

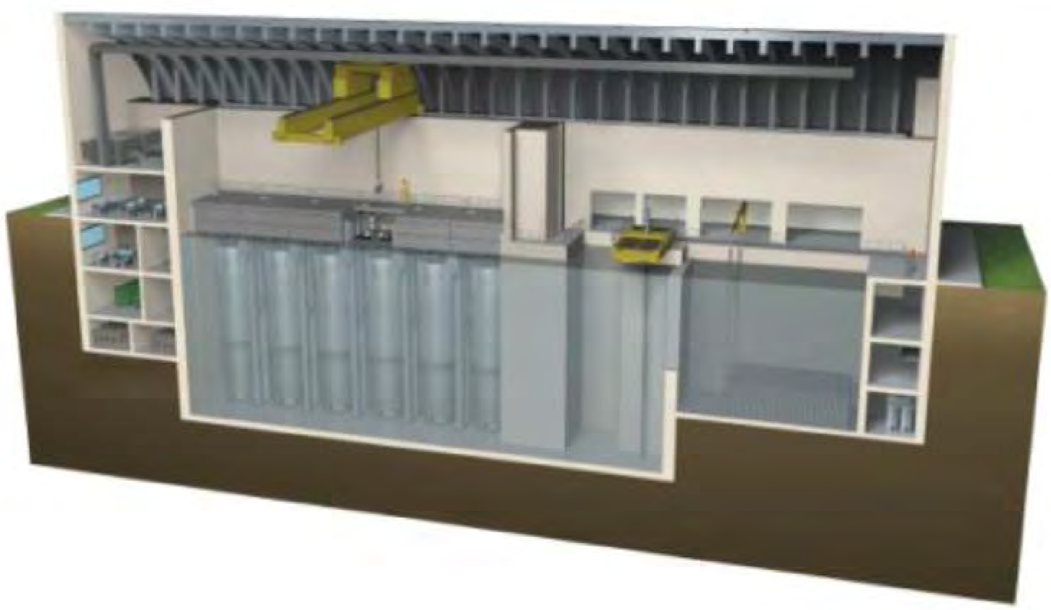


Figure 7-6 Six NuScale Modules

Figure 7-7 Conceptual NuScale Power Plant Drawing

7.1.2.2 Status of Development

In the following subsections, Black & Veatch provides a summary level discussion regarding the development status for mPower and NuScale SMR technologies. The discussion is based on information retrieved from publicly available data.

Babcock & Wilcox mPower

According to a B&W press release dated 14 July 2010, B&W and Bechtel Power Corporation have entered into a formal alliance to design, develop, and deploy an SMR based on B&W's mPower technology. The new alliance will be known as Generation mPower LLC, which is a majority-owned subsidiary of B&W. They plan for this to be the first commercially viable Generation III++ SMR power plant. The press release stated that "Depending on regulatory approval and other factors, the first plant could be deployed as early as 2020."[17]

After the announcement of B&W's further development of its mPower technology, the Tennessee Valley Authority (TVA) provided B&W with a letter of intent to begin the process of evaluating potential lead sites for installation of the mPower technology. In the TVA's 2011 Integrated Resource Plan, the TVA selected the Clinch River Breeder Reactor site at Oak Ridge as a potential site for up to six mPower reactors.[18]

By late 2013, TVA plans to submit a Construction License to the NRC for an mPower power plant to be constructed at their Clinch River site.[1]

Following the TVA application, B&W intends to apply for a DC in late 2013. The plan is to begin construction in 2015 with the first mPower unit coming online by 2018.[1]

According to World Nuclear News[11], B&W's mPower Integrated System Test (IST) facility in Virginia (announced in July 2010) is expected to begin testing and collecting data on the mPower reactor design and safety performance. Testing will support B&W's DC activities with the NRC. According to B&W's website, installment of plant process equipment for the IST facility began in April 2011. The IST facility is in its first phase of testing as of July 2013.[19]

A 16 June 2011, B&W press release announced that Generation mPower has signed a letter of intent with the TVA "that defines the project plans and associated conditions for designing, licensing, and constructing up to six B&W mPower SMRs at TVA's Clinch River site in Roane County, Tenn."[20] Generation mPower would provide engineering, procurement, and construction (EPC) services for the project give licensing and certain conditions are met. The press release also reaffirms schedules to have a construction application and DC application submitted to the NRC by 2012 and 2013, respectively.

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[17] B&W and Bechtel Form Alliance to Commercialize World's First Generation III++ SMR Nuclear Plant, press release Dated July 14, 2010, Retrieved June 2011 at: http://www.bechtel.com/2010-07-14.html
[18] Progress with mPower Project, World Nuclear News, TVA June 17, 2011, retrieved July 2013 at: http://www.world-nuclear-news.org/NN-TVA_progresses_with_mPower_project-1706115.aspx
[19] B&W Website retrieved July 2013 at: http://www.babcock.com/products/modular_nuclear/ist.html
[20] Generation mPower and TVA Sign Letter of Intent for B&W mPower Reactor Project, press release date June 16, 2011, retrieved July 2013 at: http://www.babcock.com/news_and_events/2011/20110616a.html

A report by the World Nuclear Association on the SMRs[1] provided a review on the development status of the B&W's mPower technology. According to them, B&W's present manufacturing capability in North America has the capability to produce the mPower units.

A series of press releases which provide further information of the summarized information above regarding the developmental status of B&W's mPower technology is available at Generation mPower's website.[21]

NuScale

Starting in 2000, the US DOE funded research for the development of a small nuclear power plant that might be used in multiple applications.[6] INEEL led the project with support from OSU. At the same time, OSU was gaining international recognition for its work in the development of passive safety systems that use natural circulation to provide cooling for nuclear plants.

When the DOE research project concluded in 2003, OSU scientists continued to pursue the design of a small nuclear plant that used natural circulation. Ultimately, the team at OSU built a one-third scale electrically-heated version of its plant as a test facility for this design. OSU granted NuScale Power exclusive rights to the nuclear power plant design, as well as the continued use of the test facility, through a technology transfer agreement completed in 2007.

NuScale notified the NRC in February 2008 of its intent to pursue DC for its technology. The company is in the pre-application review phase with the NRC. NuScale indicates that it is on track to file a formal request for DC in 2012.

According to its website, NuScale formed a strategic partnership with Kiewit Power in early 2008 to further develop the plans for modular manufacturing and plant construction. In 2009, "Kiewit and NuScale engineers complete a detailed preliminary plant design and cost study, which validates the plant's scalable design relying on current nuclear industry standards. Conclusion: the design is economical and can be built expeditiously."[6]

Although the development of the NuScale technology seemed promising, the company suspended all major company operations as of January 2011, according to Power-Gen World Wide.[22] An article by Erik Simmers of the Portland Business Journal further explained that a majority investor in the NuScale funding, Michael Kenwood Group LLC, had a lawsuit filed against them by the US Securities and Exchange Commission (SEC) in January 2011.[23] According to Simmers, "The SEC claims Francisco Illarramendi misappropriated some $53 million from a pair of hedge funds controlled by the Kenwood Group into bank accounts he personally controlled and then made unauthorized investments in long-term private equity deals." Francisco Illarramendi is a majority owner of the Kenwood group.

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[21] Generation mPower Press Releases available at: http://www.generationmpower.com

[22] Nuclear Reactor Developer Suspends Operation, Power-Gen World Wide, retrieved July 2013 at: http://www.powergenworldwide.com/index/display/articledisplay/8857065556/articles/powergenworldwide/nuclear/reactors/2011/01/NuScale-suspends-operations.html

[23] NuScale Power's Funding in Jeopardy, Portland Business Journal, January 20, 2011, retrieved July 2013 at: http://www.bizjournals.com/portland/news/2011/01/20/nuscale-powers-funding-in-jeopardy.html?ana=e_vert

A March 2011 press release[24] by the United States Attorney's Office, District of Columbia, stated that Illarramendi waived his right to indictment and pleaded guilty before United States District Judge Stefan R. Underhill in Bridgeport, Connecticut, on multiple counts of fraud and obstruction of justice.

Of the more than 35 million dollars NuScale had raised from investors, the Kenwood group was the principle investor, which reportedly was to invest 23 million dollars. NuScale has not been implicated in any wrong doing, but has been unable to secure additional funds to make up for those lost from the Kenwood group. Due to lack of additional funding and sources of operating cash, NuScale had to a layoff a majority of its employees in mid-March 2011.[25] NuScale maintained a core group of 15 to 20 executives and other key personnel to seek new investors.[18]

According to the World Nuclear Association, Fluor Corporation stepped in as major equity investor in October 2011 with over $30 million for 55 percent of NuScale. NuScale is expected to submit an application for US design certification in 2015 with technology brought to market in the near-term.

7.2 PERFORMANCE AND EMISSIONS

7.2.1 Westinghouse AP1000

The AP1000 has been designed with some load-following capability. However, most utilities have historically dispatched their nuclear units at base load, due to financial considerations (e.g., fixed O&M costs). In addition to the emissions from the nuclear reactor, the AP1000 plant includes standby diesel generators and a package boiler.

7.2.1.1 Performance

Thermal performance characteristics for the AP1000 are provided in Table 7-2.

[24] United States Attorney's Office District of Connecticut Press Release, Connecticut Hedge Fund Adviser Admits Running Massive Ponzi Scheme March 7, 2011, retrieved July 2013 at: http://www.justice.gov/usao/ct/Press2011/20110307.html

[25] NuScale Lays off most Employees, Oregon Business, retrieved July 2013 at: http://www.oregonbusiness.com/high-five/10-high-five/5000-nuscale-lays-off-most-employees

Table 7-2 Nuclear Full Load Performance Estimates

	AP1000
Reactor Output, MW (thermal)	3,420
Reactor Output, MBtu/hr (thermal)	11,660
Gross Plant Output, MW	1,200
Auxiliary Load, MW	50
Net Plant Output, MW	1,150
Steam Cycle Heat Rate, Btu/kWh	9,720
Station Net Plant Heat Rate, Btu/kWh	10,400
Station Efficiency, net percent	32.8

Notes:

1. All performance data are for information only. No guarantees apply to any of the values contained in this table.
2. Performance is for new and clean units, effects of performance degradation have not been included.
3. Heat rejection design sizing compensates for site specific ambient conditions variations.
4. AP1000 performance estimates were provided by US NRC certified Westinghouse Design Criteria Document (DCD).

7.2.1.2 Radiological Emissions

Radiological emissions from the AP1000 are closely monitored and regulated by the US NRC. Specific airborne and liquid source terms are tabulated in Appendix A.

7.2.1.3 Fossil Fuel Emissions

Table 7-3 shows the expected annual fossil fuel emissions from the plant.

Table 7-3 Yearly Fossil-Fueled Emissions

POLLUTANT DISCHARGED	AUXILIARY BOILER (1) (3) (lb/MBtu)	2 X 4,000 KW STANDBY DIESEL GENERATORS (2) (lb/MBtu)	2 X 35 KW ANCILLARY DIESEL GENERATORS (2) (lb/MBtu)
Particulates	0.5	< 0.6	< 0.9
SO_x	1.4	< 1.9	< 0.4
CO	no data	< 0.8	< 2.6
Hydrocarbons	1.4	< 0.5	< 1.0
NO_x	no data	< 9.2	< 12.2

Notes:
1. Emissions are based on 30 fired-days per year.
2. Emissions are based on 4 fired-hours per month.
3. Assumes a 25 MW, diesel-fired auxiliary boiler. Alternate 25 MW electric boiler is being proposed at some sites.

7.2.2 SMRs

7.2.2.1 mPower Performance

The expected thermal efficiency of a B&W mPower SMR plant is 31 percent (11,010 Btu/kWh) utilizing an air-cooled condenser. Each SMR would have an output of 180 MWe (quoted as of mid-2012) and would be installed in a multiple unit configuration. Thermal efficiency should improve, along with the expected output, with the use of a water-cooled condenser.[1]

7.2.2.2 NuScale Performance

Estimates of thermal efficiency were referenced from the World Nuclear Association. Each SMR would have an output of 45 MWe and would be installed in a multiple unit configuration. The thermal power rating of each NSSS is 165 MWth. Expected thermal efficiency is reported to be 30 percent (11,380 Btu/kWh) for a power plant with 12 NSSS units.

7.3 CAPITAL COSTS

7.3.1 Westinghouse AP1000

A preliminary order of magnitude capital cost estimate for the Westinghouse AP1000 single-unit plant was developed. All estimates are presented on an EPC basis, which is exclusive of Owner's costs. Owner's costs should be considered by the project developer/Owner to determine the total capital requirement for the project.

Table 7-4 captures currently reported construction costs for the Vogtle and VC Summer projects. They represent earlier configurations that were modified for containment enhancements and other upgrades. The Vogtle project has pending litigation against its primary EPC contractor, concerning upgrade costs. A new reactor project (without upgrade costs) would reflect some savings.

Table 7-4 AP1000 Construction Project Costs (2007$)

	VOGTLE UNITS 3 & 4	VC SUMMER UNITS 2 & 3
Total Certified Construction & Capital Cost	$4,418	$4,548
Current Forecast, June 2013	$4,799	$4,548

Notes:

1. Georgia Power Company's June 2013 Monthly Status Report, Public Disclosure, Docket No. 29849, dated 22 July 2013, http://www.psc.state.ga.us/factsv2/Docket.aspx?docketNumber=29849.
2. Quarterly Report to the South Carolina Office of Regulatory Staff, Submitted by South Carolina Electric & Gas Company, Pursuant to Public Service Commission Order No. 2009-104(A), Public Version, Quarter Ending 30 June 2013, http://dms.psc.state.sc.us/dockets/dockets.cfc?Method=DocketDetail&DocketID=103552.

The capital cost estimate is provided in Table 7-5. The estimate is presented in 2013 dollars. The estimate is reasonable for today's market, but as demonstrated in the last few years, is subject to the dynamic and unpredictable nature of the market. Power plant costs are subject to continued volatility in the future, and the estimate in this report should be considered primarily for comparative purposes.

Table 7-5 Westinghouse AP1000 Capital Cost Estimate (2013$)

	AP1000
Total Direct Costs	2,200
Total Indirect Costs	2,572
Estimated EPC Cost, $1,000	4,793
Net Plant Output, MW	1,150
EPC Unit Cost, $/kW	**4,168**
Owner's Cost Allowance, percentage of EPC Cost	45
Owner's Cost Allowance, $1,000	2,157
Total Project Cost, $1,000	6,950
Total Project Unit Cost, $/kW	**6,043**

Notes:

1. All EPC capital cost estimates are presented in 2013 dollars. The costs are order of magnitude estimates and are expected be within ± 30 percent of the actual EPC project cost.
2. EPC capital costs are exclusive of Owner's costs.
3. Unit EPC capital cost was based on estimated net plant output.
4. The sum of the EPC cost and the Owner's cost will equal the total project cost. Owner's cost is assumed to be 45 percent of the estimated turnkey EPC cost.

The general assumptions identify the scope of supply included in the EPC capital cost estimate. Assumptions related to direct and indirect costs and Owner's costs were provided in Section 2.0. Overall site assumptions were also provided in Section 2.0.

1. The Upper Midwestern site is considered a greenfield site and is assumed to be reasonably level and clear with no wetlands, no hazardous materials, no significant standing timber, and no endangered species.
2. No demolition of any existing structures is included in this cost estimate.
3. It is assumed site selection will be such that foundations will require cast-in-place concrete piers at an elevation to be determined below the permafrost. All excavations above the bottom elevation of the Reactor Building are assumed to be rippable rock or soils (no blasting required).
4. Estimate was based on using granular backfill materials.
5. The design of the HVAC and cooling water systems and freeze protection systems reflect a site location in a cold climate.
6. NI concrete and steel quantities were based (adjusted for AP1000 building volumes) on the actual quantities for an actual Black & Veatch project.

7. The site is assumed to have sufficient area available to accommodate construction activities including but not limited to construction offices, warehouses, lay-down and staging areas, field fabrication areas, and concrete batch plant facilities.
8. The plant features one AP1000 PWR supplying steam to a 1,200 MWe gross rated STG. No consideration was included in the estimate for possible future expansion of the facility.
9. Primary cooling for the reactor core and reactor auxiliary systems will be provided by an ACC.
10. Equipment will be designed in accordance with Nuclear Power Industry Codes in accordance with US NRC 10 CFR Part 50 and with ASME Boiler Pressure Vessel Code Sections II, III, V, VIII, IX, and XI.
11. NI equipment pricing is based on proprietary data from an EPC contract with cost adjustments for NSSS equipment.
12. Procurements will be without any Owner sourcing restrictions.
13. The estimate does not include the cost of a simulator or operator training.
14. The cost of the initial core is excluded.
15. External spent fuel storage is not included.
16. The cost of the offsite emergency operations center and simulator building is not included in the estimate.
17. The cost of switchyard is included. The plant interface will be at the high side of the main transformers.
18. All units of measure are in the US system.
19. The central administration building and training center (including The simulator) are not included.

7.3.2 SMRs

It is expected that costs for SMR nuclear power plants will vary depending on vendor, capacity size, modularity, and plant arrangement. Limited information is currently available regarding costs to engineer, procure, and construct an SMR power plant. For the mPower technology, the World Nuclear Association Small Nuclear Reactors paper states, "overnight cost for a twin-unit plant is but by B&W at about $5,000/kW." For NuScale, the same source states, "A 540 MW power plant is envisaged costing $5,000/kW on overnight basis."[1] The cost estimating basis is not stated, but it could be assumed that this is an overnight EPC cost and not an escalated total installed cost. An overnight EPC capital cost is exclusive of Owner's cost, which could be 20 to 40 percent of the overnight EPC capital cost. Escalation and AFUDC would also have to be included to escalate the cost to an expected construction date.

It is expected that the above cost is at a very high level. It could be expected that better cost data for SMR technologies may be available in future years as current original equipment manufacturer (OEM) technology matures and project experience is realized.

Although cost data are limited, an argument could be made that, compared to the conventional 1,000 (and greater) MW nuclear technologies, SMR technologies may be cost competitive. Table 7-5 provided an estimated cost of $4,168/kW (2013$) for a Westinghouse AP1000 PWR with an estimated net plant output of 1,150 MWe. In nearly all power generations systems, economies of scale provide a cost benefit for larger units (assuming the same energy conversion technology).

However, these traditional economies of scale may not be as significant with SMRs. That is, negative economies of scale for SMRs may not be as great as those of other forms of energy conversion technologies. Key drivers to realize these cost savings would be the reduced construction duration and cost savings from the shop-manufactured NSSS. In addition, SMRs have much simpler passive safety systems, which could reduce the cost of the nuclear island safety system.

7.4 O&M COSTS

7.4.1 Westinghouse AP1000

Preliminary order of magnitude estimates of O&M expenses, consisting of fixed and nonfuel variable annual expenses, were developed for the Westinghouse AP1000 option. The estimates are expressed in 2013 dollars.

All O&M estimates were generated on a consistent basis using assumptions previously listed. Assumptions specific to the development of the O&M cost estimates are provided in Table 7-6. Key O&M consumable costs were based on current market pricing. All assumptions relative to the development of the performance and capital cost estimates presented in previous sections were used in the development of the O&M cost estimates.

Preliminary estimates of O&M expenses for the Westinghouse AP1000 are provided in Table 7-7.

Table 7-6 Nuclear O&M Operating Assumptions

	WESTINGHOUSE AP1000
Fuel Cycle, months	18
Outage Duration, days	17
FOR, percent	4
CF , percent	93
Gross Plant Output, MW	1,200
Net Plant Output, MW	1,150
Total Onsite and Offsite Staff, count	700
Note: CF is a multi-year rolling average based on fuel cycle. The value here is the 12 month average CF.	

Table 7-7 Nuclear Annual O&M Cost Estimates, 2013$

O&M COSTS	SINGLE UNIT WESTINGHOUSE AP1000
Total O&M Operating Cost, $1,000	161,623
Total O&M Operating Cost, $/kW	140.5

7.4.2 SMRs

Black & Veatch was unable to find reliable data from publicly available sources for providing indications of O&M costs. O&M costs for an SMR plant will include components similar to those for other power generation technologies and will be more closely related to conventional nuclear technologies, which are well understood.

Perceived advantages of an SMR power plant compared to a conventional Nuclear power plant are the reduced overall complexity of the plant and its NSSS, and simpler passive safety systems. In addition, the refueling cycle duration is longer for an SMR unit. The estimated total O&M cost for a Westinghouse AP1000 is $17.30/MWh. According to technology vendors, design and operational advantages of an SMR may result in operational cost savings. Black & Veatch notes that these cost savings may only be realized for larger multiple module arrangements where fixed costs, such as staffing, can be distributed across a large generation capacity.

7.5 FUEL COST AND SOURCING

The AP1000 reactor contains a matrix of fuel assemblies, each with their own control and structural elements. The assemblies consist of 264 fuel rods arranged in 17 by 17 square array. The fuel rods consist of enriched uranium, in cylindrical pellet form, contained within a zirconium tube. The tubes are plugged and seal welded at both ends. The production of nuclear fuel assemblies involves four major steps:

- **Mining/Milling**--Mining involves removing various uranium bearing minerals from the ground. These various minerals are collectively known as uranium ore. Three methods of mining are employed today: open pit mining, underground mining, and in situ leaching (solution mining), where uranium ore is dissolved in a solution and pumped to the surface. Uranium ore is then converted into U3O8 at a uranium mill.
- **Conversion**--Conversion involves converting U3O8 to uranium hexafluoride (UF6) for uranium enrichment. Uranium hexafluoride is used in enrichment because of its unique properties. It can conveniently be used as a gas for processing, as a liquid for filling or emptying containers or equipment, and as a solid for storage, all at temperatures and pressures commonly used in industrial processes.
- **Enrichment**--Enrichment involves artificially increasing the percent of fissile material (U235) in fertile material (U238) from 0.7 percent (natural) to levels useful for various applications. Current light water reactor (LWR) designs require enrichment levels of 3 to 5 percent. Common enrichment methods include gaseous diffusion, centrifuge, and separation nozzle.
- **Fuel Fabrication**--Fuel fabrication involves converting enriched uranium hexafluoride to uranium dioxide (UO2) and creating fuel pellets through a sintering process. The pellets are loaded into zirconium tubes, with expansion springs, plugged, and sealed welded in place. Fuel assemblies are constructed from 264 rods, thimble guide tubes, flow nozzle blocks, grids, and control rods.
  - Both B&W and NuScale will utilize traditional UO2 nuclear fuel enriched to less than 5 percent. Sourcing of fuel for these technologies is expected to be the same as that for larger, more traditional nuclear plant in operation today. Raw fuel costs are also expected to be the same.
  - The cost to refuel the reactors is uncertain at this time because of limited information. As with any nuclear technology, the fuel must be processed and packaged to fit the specific technology and application. This processing will also be required for an SMR.

Spot market uranium pricing has been continuously falling since February 2011 to its current price of $34/lb (down 45 percent), a level not seen since November 2005. Unfortunately, raw uranium only represents about 15 percent of the total fuel cost. Even though $40/lb is roughly considered a marginal cost-of-production for uranium mining, the price is expected to remain at this level into Q1/2014 before recovery. The market is flush with supply due to recent retirements and the temporary shutdown of Japanese reactors. Principal buyers (i.e. nuclear utilities) usually maintain several years worth of supply, so it may take time to exhaust market supplies.

According to the Nuclear Energy Institute (NEI) a typical 1,000 MWe BWR or PWR, the approximate cost of fuel for one reload (replacing one third of the core) is about $40 million, based on an 18-month refueling cycle. The average fuel cost at a nuclear power plant was 0.77 cents/ kWh (escalated to Q4 2013 dollars).[26] A large portion of US reactors are withholding their O&M costs for confidentiality reasons. Assuming a station efficiency of 32.8 percent (10,400 Btu/kWh) the fuel cost would be approximately $0.74 per MBtu of heat input into the reactor by the nuclear fuel. The following table summarizes nuclear fuel costs.

Table 7-8 Nuclear Fuel Costs (2013$)

	FUEL COST
Nuclear Fuel Cost, $/MWh	7.70
Nuclear Fuel Cost, $/MBtu	0.74
Note: Fuel cost in $/MBtu based on a fuel cost of 7.70 $/MWh and a station efficiency of 32.8 percent (10,400 Btu/kWh).	

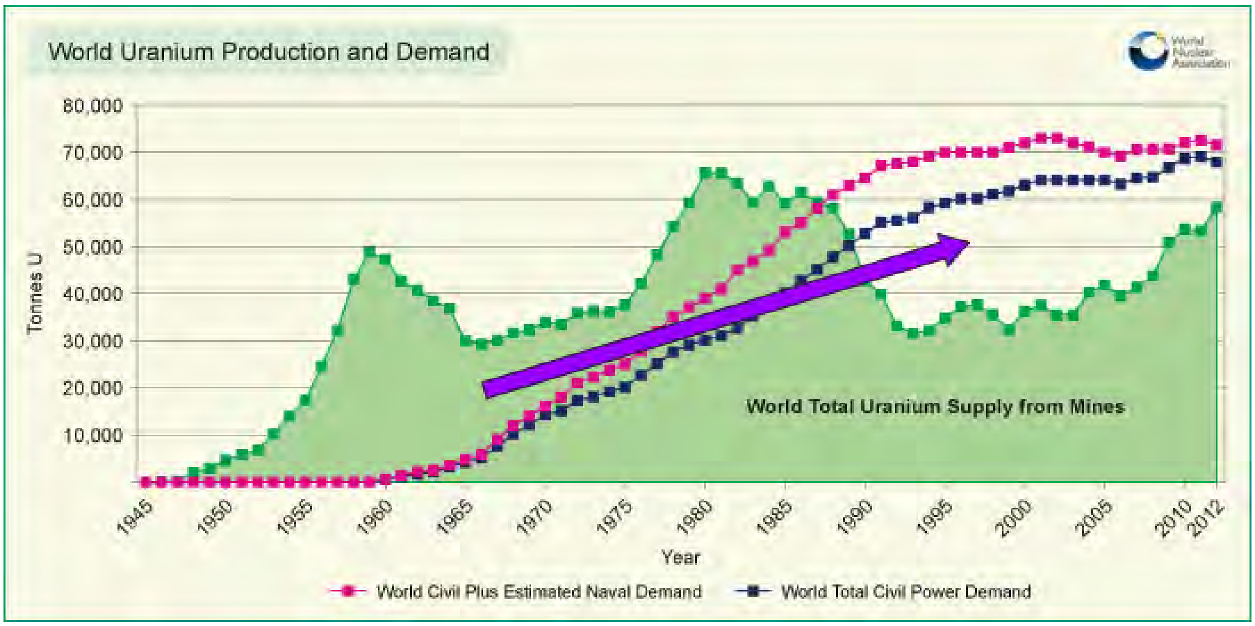


Figure 7-8 World Uranium Production and Demand Curves[27]

[26] Nuclear Energy Institute, available at: www.nei.org
[27] World Nuclear Association, Uranium Markets. Retrieved October 2013: http://world-nuclear.org/info/Nuclear-Fuel-Cycle/Uranium-Resources/Uranium-Markets/#.Uk8snRDRPb0.

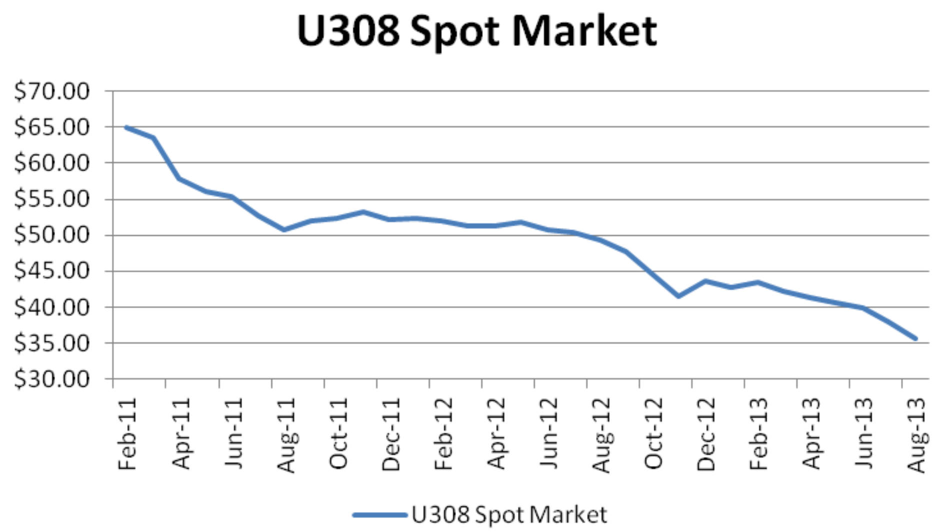


Figure 7-9 Uranium 308 Spot Market Costs[28]

7.6 APPLICABLE INCENTIVES

The US Federal Energy Policy Act of 2005 provides both direct and indirect applicable incentives for the development of new nuclear units. Direct incentives consist of production tax credits (PTCs) which can be clearly translated to cost savings which could be experience by a developer. Standby Support and Loan Guarantees may have the potential to provide indirect savings. With the Federal government providing Standby Support and Loan Guarantees, developers may experience savings in costs incurred in project overruns due to NRC scheduling, insurance premiums, and cost of financing. However, at this time, the magnitude of those savings is unclear and could vary from developer to developer.

On August 13, Standard & Poor published, an assessment of credit considerations associated with the new reactor designs. Specific categories of consideration include: licensing certainty, capital costs, cost certainty, fuel and O&M costs, theoretical lifetime costs, construction record, and commercial track record. The reactor designs with active safety systems (e.g., ABWR, APWR, EPR) could face more uncertainty in the areas of capital costs, cost certainty, fuel and O&M costs, and theoretical lifetime costs.

7.6.1 Production Tax Credit Status

The US Internal Revenue Service published Notice 2006-40, Bulletin No. 2006-18, May 1, 2006, providing interim guidance on tax credits for certain levels of production from advanced nuclear power facilities. The notice titled “Credit for Production from Advanced Nuclear Facilities” sets forth rules under which a taxpayer can claim the tax credit. 6,000 MW of available credits will be divided on a pro-rata basis for facilities. The following summarizes the production tax credit:

[28] Index Mundi. Retrieved September 2013: http://www.indexmundi.com/.

- Combined construction and operating license application submitted by 31 December 2008.
- Construction started by 1 January 2014.
- Commercial operation by 1 January 2021.
- Prorated more than 6,000 MW of new generation.
- $125 million max per 1,000 MW per taxable year.
- PTC -- $18/MWh for an 8 year period, pro-rated (shared among developers) for 6,000 MW of new nuclear.

7.6.2 Standby Support Status

The final 10 CFR Part 950 Rule was issued 11 August 2006, establishing regulations for the Secretary to enter into contracts with sponsors of an advanced nuclear facility that cover a total of six reactors consisting of not more than three different reactor designs, in accordance with statutory requirements. The risk insurance coverage is for certain delays attributed to the US NRC regulatory process or litigation. Two notices of Intent to Request a Conditional Agreement have been received by the US DOE. No requests received or contracts issued. The following summarizes the Stand-by support status:

- Financial backstop for up to six reactors.
- Coverage for NRC failure to comply with schedules.
- Protection against litigation delays.
- Up to three advanced reactor designs covered (including AP1000).
- Up to $500 million for the first two reactors.
- $250 million for the next four reactors.

7.6.3 Loan Guarantees Status

The final 10 CFR 609 Rule was issued 23 October 2007, establishing regulations for the Secretary to make loan guarantees for projects that "avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases; and employ new or significantly improved technologies in service in the US at the time the guarantee is issued."

The US DOE issued a solicitation announcement on 30 June 2008 (amended on 11 July 2008, Reference Number DE-FOA-0000006), inviting submission of applications for loan guarantees under Title XVII of the Energy Policy Act of 2005. Nuclear plant facilities solicitation was broken down into two application parts that must be received by US DOE. The application schedule is as follows:

- Solicitation Issue Date — 30 June 2008
- Part I Submissions Due — 29 September 2008
- Initial Rankings Issued — 29 October 2008
- Part II Initial Submissions Due — 19 December 2008

- Part II Follow-on Submissions Due — Every 90 days following the Part II Initial Submission Due Date until execution of a Loan Guarantee Agreement or termination by US DOE.

Six companies responded to the solicitation: two Part I nuclear plant applications, three others provided intents to submit for nuclear plants, and one fuel cycle facility submitted an application. Calvert Cliffs-3 Nuclear Project (a subsidiary of Constellation Energy-EDF Alliance Unistar) Dominion Virginia Power, and United States Enrichment Corporation have submitted their Part I applications for the Calvert Cliffs 3 nuclear plant site (July 31), North Anna 3 nuclear plant site (August 15), and American Centrifuge Plant (ACP) fuel cycle site (July 25), respectively.

The Senate Appropriations Committee authorized full funding for the FY2009 $33.3 billion energy and water development appropriations measure on 10 July 2008. The measure also extended indefinitely US DOE's ability to obligate $38.5 billion in clean energy loan guarantees.

In February of 2010, the Obama Administration expanded the nuclear power loan guarantee authority by $36 billion, making the total program funding $54 billion. Later in February, Southern Company's Vogtle project (2-Unit) was awarded a $ guarantee of their $83 billion in loans.

7.7 US NRC LICENSING

In 1989, the US NRC started revising the process used to license nuclear plants. Historically, plants were given Construction Permits to start construction with only a preliminary design. This left final US NRC safety assessments and public hearings, necessary to obtain the Operation Permit, until the plant was nearly complete. Changes and delays at this point were very costly. The new process combines the two permit steps into a single Construction and Operating License Application (COLA) process, followed by a verification at completion of construction. The new process provides for Design Certification (DC), Early Site Permit (ESP), as well as COLA using detailed design details. The new process shortens the licensing process and eliminates most of the financial risk experienced by the previous generation of plants.

The DC allows plant designers to secure advance US NRC approval of standard plant design. Subsequent plants can be ordered and licensed without repeating the process. Design standardization offers many advantages, including lower costs, reduced construction and O&M costs, and shorter licensing schedules. A DC takes approximately 36 to 60 months to complete US NRC review.

ESP's enable companies to obtain US NRC approval for a given site before deciding to build a plant. ESP applications include three important elements: a site safety analysis, an environmental analysis, and emergency planning information. An ESP takes approximately 12 to 24 months to develop and up to 33 months for US NRC review and public hearings.

The COLA process references a DC and may include an ESP. All issues with design and/or the site that have already been approved will be considered resolved. Only the remaining issues not resolved earlier will be addressed in the US NRC review and public hearings. The entire COLA process could take as long as 42 months.

7.7.1 Current Delays in Licensing

On 27 January 2006, the NRC issued the final design certification rule (DCR) for the AP1000 design. The US NRC later issued a revised Final Design Authorization, based on Revision 15 of the Westinghouse design control document (DCD), on 10 March 2006.

In a joint letter dated 8 March 2006, NuStart Energy Development, LLC (NuStart) and Westinghouse Electric Company, LLC (Westinghouse) stated that they would be submitting the AP1000 technical reports to the US NRC for review during the preapplication phase for the Bellefonte COLA. These reports provided the following:

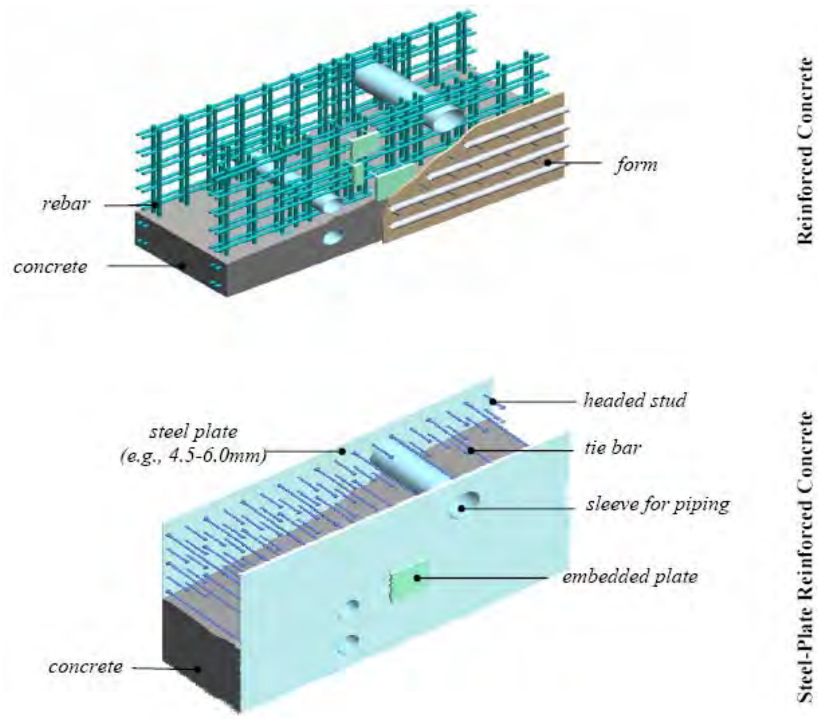
- Information needed to close all or part of specific generically applicable COLA items in the AP1000 certified standard design.
- Standard design changes that are a result of the AP1000 detailed design efforts.
- Specific standard design information in areas or for topics where the AP1000 DCD focused on design process/methodology and design acceptance criteria.
- Deferral of COLA information items to as-built requirements [e.g., inspection, test, analysis, and acceptance criteria (ITAAC)].

Most of the technical reports relate to the closing or partial closing of the AP1000 DCD COLA information items; however, the largest review effort will center on the expected design changes. Those design changes include a redesign of the pressurizer, a revision to the seismic analysis to allow an AP1000 reactor to be constructed onsite with rock and soil conditions other than the hard rock conditions certified in the AP1000 DCR, changes to the instrumentation and control (I&C) systems, a redesign of the fuel racks, and a revision of the reactor fuel design. Another area requiring significant resources will be the review of DAC-related items, such as the technical reports on human factors engineering, the I&C design, and piping. Additionally, Westinghouse submitted one report covering numerous COLA information items, which can be completed only after the plant is built. Westinghouse proposes to convert those items to either ITAAC, license conditions, or license commitments.

On 26 May 2007, Westinghouse submitted an application to amend the AP1000 DCR and Revision 16 of the AP1000 DCD. Revision 16 contains changes proposed in technical reports, some of which have not yet been reviewed by the NRC staff.

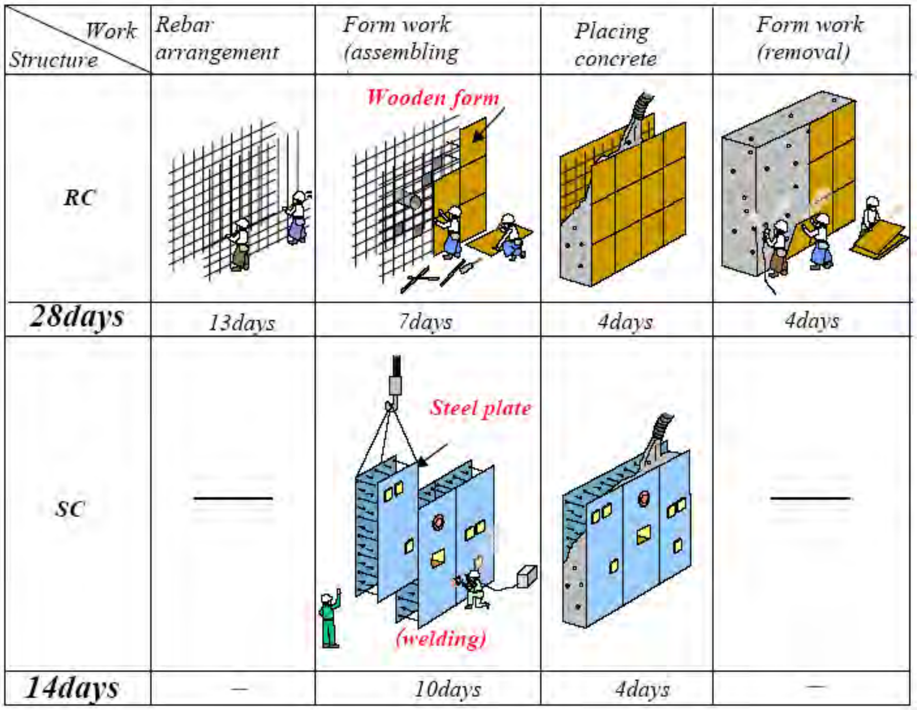
On 22 September 2008, Westinghouse updated its application to amend the AP1000 DCD. The update, Revision 17, contains changes from those submitted in Revision 16. The changes are summarized in the September 22nd letter. On 14 October 2008, Westinghouse provided a corrected set of the Revision 17 DCD electronic files, to update portions of the revision change roadmap and include additional change bars in the margins that had inadvertently been omitted in the initial submittal. The linked public version of Revision 17 contains the corrected files.

The steel plate reinforced shield building represents an extension of the modular design concepts from the rest of the structure and component module designs. The differences can be seen on Figure 7-10 and Figure 7-11. The changes made to facilitate this type of construction have come into question by the NRC.



(Reference: Schlaseman, C., "Application of Advanced Construction Technologies to New Nuclear Power Plants," MPR-2610, Revision 2, DOE Contract DE-AT01-02NE23476, September 2004.)

Figure 7-10 Comparison of Reinforced Concrete Construction



(Reference: Schlaseman, C., "Application of Advanced Construction Technologies to New Nuclear Power Plants," MPR-2610, Revision 2, DOE Contract DE-AT01-02NE23476, September 2004.)

Figure 7-11 Comparison of Construction Schedules for Reinforced Concrete

In the 15 October 2009 letter to Westinghouse, the US NRC stated, "Specifically, the design of the steel and concrete composite structural module... must demonstrate the ability to function as a unit during design basis events; the design of the connection of the... module to the reinforced concrete wall sections of the shield building must demonstrate the ability to function during design basis events; [and] the design of the shield building tension ring girder, which anchors the shield building roof to the wall, must be supported by either a confirmation test or a validated (or benchmarked) analysis method." It further added that Westinghouse will have to, "provide modifications to the design and testing." The current schedule reflects a target date of December 2010 for the Final Safety Evaluation Report, but the NRC considers this subject to change.

Both Westinghouse and Shaw have announced their confidence in maintaining the current schedule of the DC by the end of 2010. Westinghouse is addressing NRC concerns to the shield building design. Enhancements to the shield building will be addressed in a revised Shield Building Report with increased analysis. Westinghouse will also demonstrate that the AP1000 shield building design is safe, robust, and meets regulatory requirements with testing at Purdue University's Bowen Laboratory.

7.7.2 Status of AP1000 Construction Worldwide

Table 7-9 provides the current status of Westinghouse AP1000 construction activities worldwide.

Table 7-9 Status of Westinghouse AP1000 Construction Worldwide

OWNER	PLANT	UNITS	LOCATION	C.O.	STATUS
Southern Company	Vogtle U3/4	2	Waynesboro, Georgia	Unit 3: Q4-2017 Unit 4: 2018	June 2013 Engineering, Procurement and Construction is approximately fifty percent (50%) complete. Construction Completion Status includes: ▪ Placement of 990-ton U3 Containment Vessel (CV) Bottom Head completed. ▪ U4 Nuclear Island (NI) rebar installation commenced. ▪ Major activities continue to include: Nuclear Island (NI) foundation, Containment Vessel (CV) assembly, turbine building foundation, cooling tower foundation, raw water intake structure preparation, switchyard modifications and new transmission installation. Equipment and Fabrication Status completed: ▪ The 450-ton U3 Reactor Vessel (RV) and Closure Head delivered onsite; U4 RV & CH still in fabrication. ▪ U3 300-ton Deaerators arrived onsite; U4 DAs still in fabrication. ▪ U3 2x Moisture Separator Reheaters (MSR) received onsite; U4 MSRs still in fabrication. ▪ U3 Feedwater Heaters delivered onsite; U4 FWHs still in fabrication. Project schedule has been amended to reflect Q4-2017 and 2018 for Units 3 and U4, respectively. Project to date cost actuals have been redacted, but appear to be plan (approximately $2.5 billion).
South Carolina Electric & Gas Co.	VC Summer U2/3	2	Jenkinsville, South Carolina	Unit 2: Q4-2017/Q1-2018 Unit 3: 2019	June 2013 Construction Completion Status includes: ▪ Placement of 990-ton U2 Containment Vessel (CV) Bottom Head completed. ▪ U2 Turbine Building Basemat and 3 walls to 12 feet; including placement of lower half of Condenser B. ▪ Preparation for Placement of the U3 Nuclear Island Basemat. ▪ U3 CV Bottom Head and stand welding.

OWNER	PLANT	UNITS	LOCATION	C.O.	STATUS
					■ U2 CV Rings 1 & 2 largely complete & seams welded; U3 CV Rings fabricating and enroute to site. ■ Fabrication of Sub-Modules recovery plan includes relocating U2 CA04 module to site. ■ Setting Cooling Towers 2A & 3A precast panels are 75% & 25% complete; foundation piling and rebar/formwork complete on 2B & 3B; and U2 & U3 Cooling Water Pump Stations mudmats placed. ■ Switchyard work ongoing. Equipment and Fabrication Status includes: ■ The 450-ton U2 Reactor Vessel (RV) and Closure Head delivered onsite; U3 RV & CH still in fabrication. ■ U2 Steam Generators have been hydrotested and will ship Q4 2013; U3 SG still in fabrication. ■ U2 & U3 Reactor Coolant Pumps (RCP), Core Makeup Tanks, and Accumulators are still in fabrication. ■ U2 300-ton Deaerators arrived onsite; U3 DAs still in fabrication. ■ U2 2x Moisture Separator Reheaters (MSR) received onsite; U3 MSRs still in fabrication. ■ U2 Reactor Coolant Loop Piping (RCL) surge lines onsite; cold and hot legs to be shipped Q4 2013; U3 RCL still in fabrication. ■ U2 Main Steam Turbine Generator (STG) HP & LP casings and rotors arrived onsite; U3 STG still in fabrication. ■ U2 & U3 Squib Valves in fabrication. ■ Information Technology, Configuration Management information System (CMIS), site Fiber backbone, and CHAMPS Work Management System installations on schedule.

OWNER	PLANT	UNITS	LOCATION	C.O.	STATUS
					Chicago Bridge & Iron, Lake Charles, LA (CB&I-LC) Construction Module Fabrication Status: ▪ Production problems resolved with new management and and some fabrication moved offsite. Overall schedule slipped 6 to 12 months. Engineering Completion Status, plant design packages issued for construction (IFC) as of June 30, 2013, is at 82.4% complete. Project Cash Flow is slightly below target, with an anticipated year end cumulative amount of $2.513 billion ($364.7 million below target).
State Nuclear Power Technology Corp. (SNPTC)	Haiyang U1/2	2	Shandong Province, China	Unit 1: 12/2014 Unit 2: 3/2016	U1 Containment Vessel (CV) Top Head placement complete March 29, 2013. The site will eventually have six or eight units, and in March 2009, the preliminary works for units 3 and 4 were approved.
SNPTC	Sanmen U1/2	2	Zhejiang Province, China	Unit 1: 12/2014 Unit 2: 10/2015	U1 Containment Vessel (CV) Top Head placement complete January 29, 2013. Two repaired Reactor Coolant pumps (RCP) have been returned to site on August 2013. Three of four U1 Reactor Coolant Pumps originally returned to vendor for repair, after a piece of impeller blade was discovered to have separated from the main impeller casting. The repair involved replacement of internal components including the impeller and guide vanes, and factory re-testing. Another six units are envisaged for the Sanmen site.

7.8 NUCLEAR PLANT SITING

Nuclear plant siting requires the screening of individual sites against a wide variety of health and safety, environmental, socioeconomic, and engineering and cost related criteria. Table 7-10 provides specific siting requirements for the AP1000.

Table 7-10 Westinghouse AP1000 Siting Requirements

CRITERIA	SINGLE UNIT	TWIN UNIT
Plant Area	530 ft x 790 ft 419,00 ft2 (9.6 acres)	530 ft x 1,580 ft 419,00 ft2 (19.2 acres)
Cooling Towers	808 ft x 808 ft 653,000 ft2 (15 acres)	808 ft x 1,616 ft 653,000 ft2 (30 acres)
Heat Rejection Main	Two thirds of 3,400 MWt reactor output, or 2,250 MWt discharged per unit. Approximately 450,000 to 750,000 gpm of circulating water flow rate, depending on technology and environmental conditions. Up to 4 percent for makeup water. 25/50 acres for mechanical draft cooling towers, for single/twin unit respectively.	
Heat Rejection Auxiliary	Auxiliary cooling for service water needs of about 500 gpm.	
Ultimate Heat Sink	None. The passive cooling design of the AP1000 does not require a separate safety-grade UHS.	
Substation	4 Bay, BAAH, 500 kV switchyard, 12 acres	6 Bay, BAAH, 500 kV switchyard, 18 acres
Excavation	40 feet nominal depth	
Seismology	0.30 g peak ground acceleration 1,000 ft/sec shear wave velocity	
Exclusion Area Boundary	2,640 ft	

7.9 CONSTRUCTION SCHEDULE

Modules are an integral part of the AP1000 design concept. There are approximately 600 modules in the design. All major pipe areas are modularized. Large modules carry 90 percent of the pipe, valves, and instruments for containment systems. Of all the pipe welds inside containment, 65 percent will be made in shops and shipped in modules. Modularization represents the single largest driver of schedule reduction.

The Westinghouse AP1000 schedule (Figure 7-12) includes 18 months for site preparation and mobilization, 36 months for plant construction (pour NI basemat to fuel load complete), and 6 months from fuel load to commercial operation.

7.9.1 Site Preparation

Site preparation includes site clearing and grubbing, NI excavation, underground utility installation, circulating water piping, and preparation for pouring the NI basemat. Field assembly of the containment vessel bottom head and fabrication of the cradle rebar module also occur during this period. Site preparation is estimated at 18 months.

7.9.2 Construction Phase

First structural concrete pour begins with the NI basemat. The construction phase is estimated at 36 months. Construction phase critical path activities include the following:

- Installation of pedestal rebar modules, pedestal concrete, cradle rebar module, and setting of the containment vessel bottom head.
- Welding of embedded piping to the containment vessel head, setting of two room modules, and placing of concrete under the containment vessel.
- Forming and pouring of concrete walls to elevation 84 feet' and epoxy coating of concrete in Area 4.
- Installation of resin slurry system at Elevation 66 feet, the lowest containment building level, and floor construction at Elevation 84'-6" in Area 4.
- Equipment and floor installation up to Elevation 118 feet in Areas 3 and 4.
- Additional floor and wall construction activities.

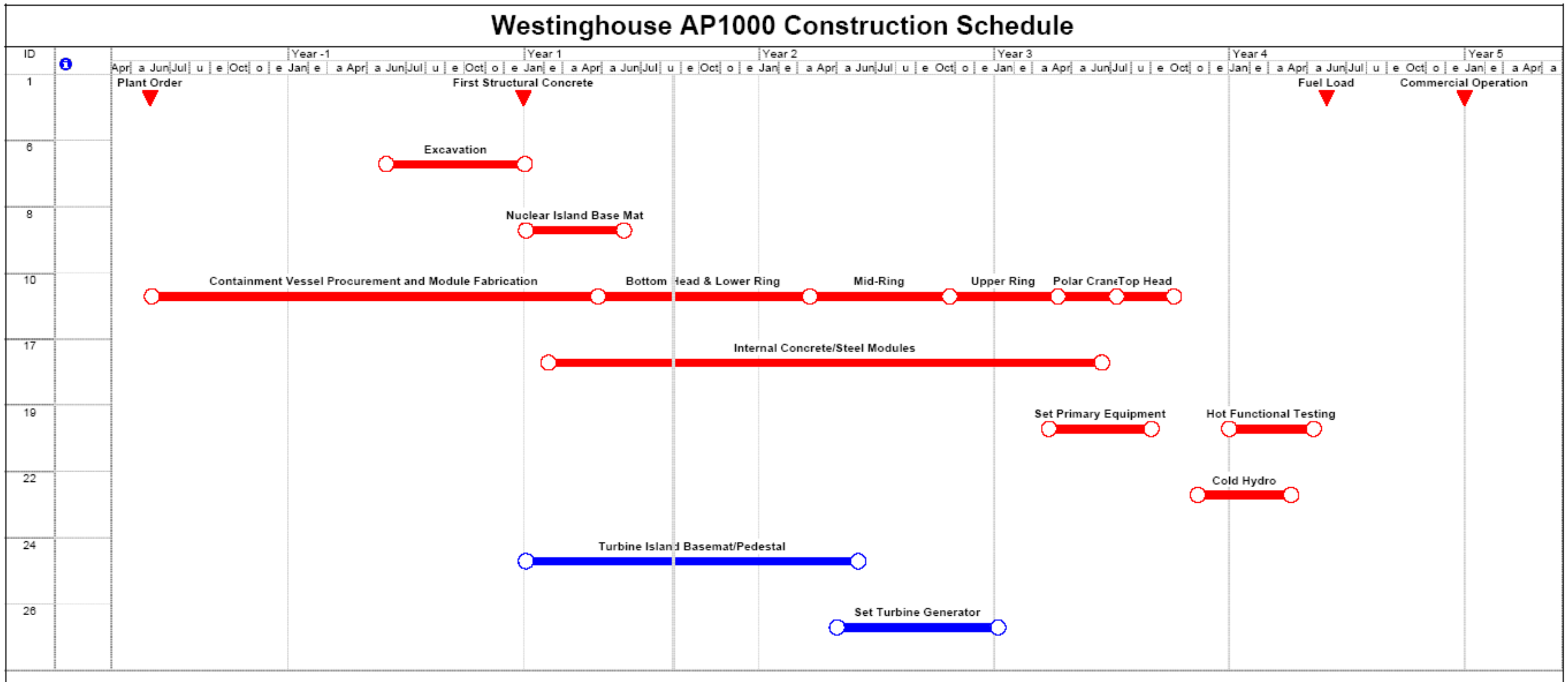


Figure 7-12 Westinghouse AP1000 Construction Schedule

7.10 CASH FLOW SUMMARY

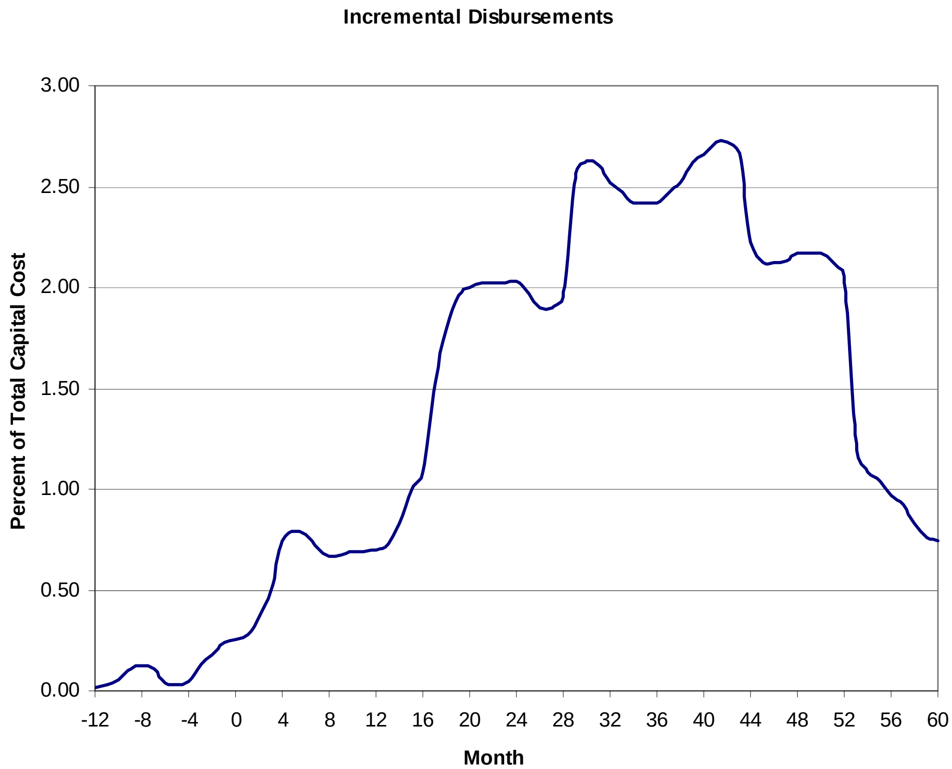
The cash flow summary for the AP1000 is shown in Table 7-11. The cash flow summary is also portrayed graphically on Figure 7-13. The cash flow data include incremental and cumulative cash flows and were calculated as a percentage of total capital cost versus time. The cash flow summaries were based on the construction schedules described in the previous section.

Table 7-11 AP1000 Cash Flow Estimates

MONTH	INCREMENTAL	CUMULATIVE
-12	0.02	0.02
-11	0.03	0.05
-10	0.05	0.10
-9	0.11	0.21
-8	0.12	0.33
-7	0.11	0.44
-6	0.04	0.48
-5	0.03	0.51
-4	0.05	0.56
-3	0.13	0.69
-2	0.18	0.87
-1	0.24	1.11
1	0.28	1.40
2	0.36	1.76
3	0.51	2.27
4	0.74	3.01
5	0.79	3.79
6	0.77	4.57
7	0.71	5.28
8	0.67	5.94
9	0.68	6.62
10	0.69	7.31
12	0.70	8.00
13	0.73	8.73
14	0.83	9.57
15	1.00	10.57
16	1.09	11.65
17	1.53	13.18
18	1.79	14.97
19	1.96	16.93

MONTH	INCREMENTAL	CUMULATIVE
20	2.00	18.93
21	2.02	20.95
22	2.02	22.97
23	2.02	24.99
24	2.03	27.02
25	1.97	28.99
26	1.90	30.89
27	1.90	32.79
28	1.95	34.74
29	2.56	37.31
30	2.63	39.93
31	2.60	42.54
32	2.52	45.06
33	2.47	47.53
34	2.42	49.95
35	2.42	52.38
36	2.42	54.80
37	2.47	57.27
38	2.52	59.79
39	2.62	62.41
40	2.66	65.07
41	2.72	67.79
42	2.72	70.51
43	2.67	73.18
44	2.22	75.40
45	2.12	77.52
46	2.12	79.64
47	2.13	81.78
48	2.17	83.95
49	2.17	86.12
50	2.17	88.29
51	2.12	90.41
52	2.06	92.47
53	1.20	93.67
54	1.08	94.75
55	1.04	95.79
56	0.97	96.76

MONTH	INCREMENTAL	CUMULATIVE
57	0.92	97.69
58	0.83	98.52
59	0.76	99.28
60	0.74	100.0



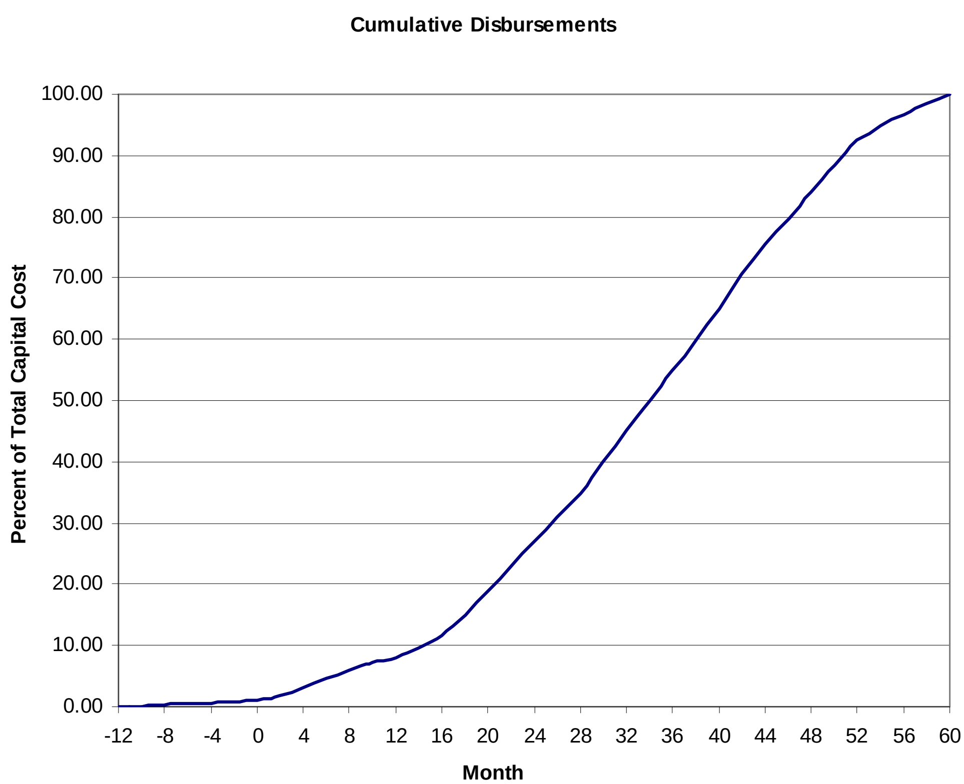


Figure 7-13 Nuclear Cash Flow Curves

7.11 REFUELING OUTAGES AND MAINTENANCE SCHEDULES

The AP1000 operates on a 18 month fuel cycle, replacing a third of the core each outage. The duration of the refueling outage is approximately 17 days, during which time the utility would purchase replacement power or operate other fossil resources located at other sites. The refueling outages are scheduled in the fall or spring to avoid maximum system load seasons.

7.12 SPENT FUEL

Long-term disposal of spent fuel will be addressed via (1) long-term deep geologic disposal at Yucca Mountain and (2) accruing funding on an ongoing use basis. Other options with spent fuel recycling, as in Europe and Japan, are also being investigated. Current uncertainties with the deployment date for Yucca Mountain are being addressed with low cost, scalable independent spent fuel installations (ISFSIs) at plant sites. Short-term uncertainty is not expected to adversely impact long-term viability of the PBMR facility.

The spent fuel is periodically removed from the core during refueling outages, and stored in the spent fuel pool (wet storage). The spent fuel is located inside the fuel handling building, which is part of the NI. There are 616 racks in the pool for securely holding and cooling the spent fuel assemblies. Maintaining the capacity to completely off-load the operating core (157 assemblies), the remaining 459 racks (616 to 157) provide approximately 15 years of storage capacity.

Beyond those durations, onsite ISFSIs would need to be utilized if Yucca Mountain is not receiving spent fuel. ISFSIs (e.g., dry storage) can be constructed onsite, and staged to meet plant requirements. ISFSIs utilize the natural circulation of air to cool the spent fuel assemblies. A typical ISFSI installation occupies approximately 15 acres, and can be accommodated inside the existing Owner protected area. ISFSIs can only be utilized after the spent fuel has been cooled in the spent fuel pool for a period of time, undergoing further radioactive decay (to lower temperatures and radiation levels).

7.12.1 Yucca Mountain

In August 2013, the US Court of Appeals for the District of Columbia Circuit issued a writ of mandamus ordering the US Nuclear Regulatory Commission to comply with federal law and restart its review of DOE's Yucca Mountain repository license application.

The Yucca Mountain licensing review was suspended in 2011. The former NRC Chairman Gregory Jaczko cited the agency's lack of funds for completing that work as the reason for the suspension.

The NRC is proceeding with the development of plans for compliance with the court order, and restarting the licensing process.

The Yucca Mountain Litigation: Breach of Contract Under the Nuclear Waste Policy Act of 1982 is ongoing. There has been a precedent set, however, by companies filing and winning suits against the US DOE to recover this extra cost:

- US DOE to pay Energy Northwest nearly $56.9 million in damages for breach of contract involving the Yucca Mountain nuclear repository project (SNL, March 1, 2010).
- $56 million awarded to Duke for spent fuel costs associated with its Oconee, McGuire, and Catawba plants (Reuters, March 12, 2007).
- $43 million awarded to Pacific Gas & Electric Company's Humboldt Bay and Diablo Canyon for damages resulting from the US DOE's failure to begin accepting spent fuel (Nuclear Energy Overview, October 23, 2006).
- $143 million awarded to Connecticut Yankee ($34.1 million), Maine Yankee ($75.8 million), and Yankee Rowe ($32.9 million) because the government failed to take away their used reactor rods. (Associated Press, October 4, 2006).

It should be noted that the financial risk involved with building ISFSI facilities is minimal because they can be incrementally built (i.e., built on an as-needed basis) and the cost can be successfully recovered from the DOE.

7.13 LOW LEVEL RADWASTE DISPOSAL

The AP1000 design incorporates a variety of features to help the utility minimize low level radwaste (LLRW) disposal. During normal plant operation, an average of 1,964 cu ft/yr LLRW is expected to be shipped offsite.

Figure 7-14 shows the Low Level Waste Compacts currently in operation. The Alliant Energy territory lies within the Midwest compact states. The Low Level Radioactive Waste Policy Amendments Act of 1985 gave states the responsibility for disposal of their own low level waste and encouraged the formation of compacts to share common disposal facilities.

7.14 DECOMMISSIONING

Nuclear plants are licensed for 40 years. Life extensions for another 20 years may be provided by the US NRC, after careful review. At the conclusion of the 40 or 60 year life, the plant owner is obligated to Decommission and Dismantle (D&D) the power island structures. Alternatively, units may be kept in Safe Store condition, and D&D postponed to coincide with the D&D date for an adjacent newer unit.

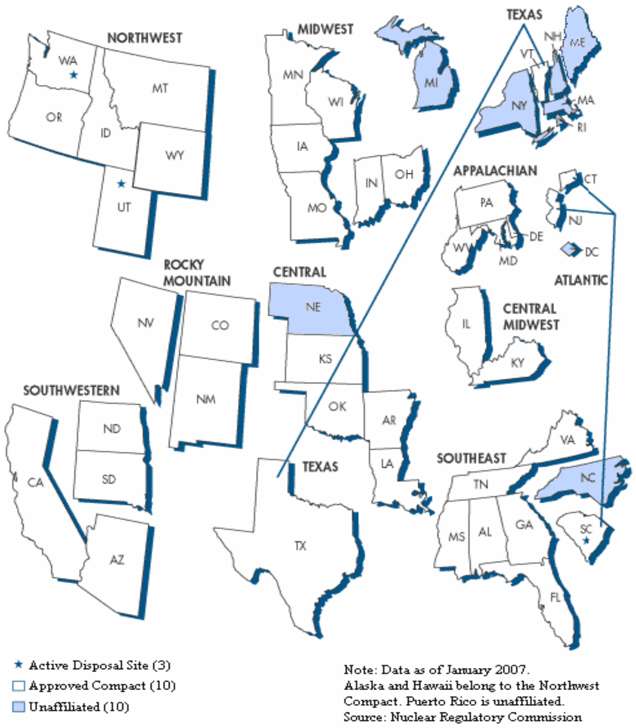


Figure 7-14 Low Level Waste Compacts

The three active, licensed, low level waste disposal facilities include the following:

- **EnergySolutions Barnwell Operations (located in Barnwell, South Carolina)**--Currently, this Energy Solutions facility accepts waste from all US generators except those in the Rocky Mountain and Northwest compacts. As of 2008, this facility only accepts waste from the Atlantic compact states (Connecticut, New Jersey, and South Carolina). It is licensed by the State of South Carolina to receive wastes in Classes A-C.
- **US Ecology (located in Richland, Washington)**--This facility accepts waste from the Northwest and Rocky Mountain compacts. It is licensed by the State of Washington to receive wastes in Classes A-C.
- **EnergySolutions Clive Operations (located in Clive, Utah)**--This facility accepts waste from all regions of the United States. It is licensed by the State of Utah for Class A waste only.

8.0 Renewable Energy Technology Options

This section characterizes the various renewable energy technologies that could potentially be implemented in Alliant Energy's service territory.

Renewable energy technologies are diverse and include biomass, biogas, biofuels, waste-to-energy (WTE), hydroelectric, solar, wind, and geothermal energy. Steady advances in equipment and operating experience spurred by government incentives have led to the maturation of several renewable technologies. The technical feasibility and cost of energy from nearly every form of renewable energy have improved since the early 1980s.

The economic viability of renewable energy technologies varies from technology to technology and depends in large part on the quality of the specific renewable resources available within a given region (e.g., within the service territory of Alliant Energy). Nevertheless, the generation capacity of renewable energy technologies is rapidly expanding and making meaningful contributions to the world's electricity supply. Electrical generation from these technologies represented approximately 12 percent of the total electrical generation within the United States in 2012. (Excluding conventional hydro, renewable energy technologies represented approximately 5 percent of the total electrical generation in 2012.)[29]

This section provides an overview of the following renewable energy technologies:

- Wind.
- Solar:
  - Solar photovoltaic (PV).
  - Solar thermal electric.
- Solid biomass:
  - Direct-fired.
  - Co-fired.
  - Biomass IGCC.
- Biogas:
  - Anaerobic digestion.
  - LFG.
- Biofuels:
  - Ethanol.
  - Biodiesel.
- WTE:
  - Mass burn.
  - RDF.

[29] US Department of Energy, Energy Information Administration, "Electric Power Monthly, with Data for May 2013". Released July 2013.

- Hydroelectric:
- Geothermal.

Generally, each technology is described with respect to its principles of operation, applications, resource characteristics, cost and performance, environmental impacts, and outlook for Alliant Energy. The alternatives have been presented with typical ranges for performance and cost, based on representative sizes and installations in or near Alliant Energy's territory. However, the generic data provided should not be considered as definitive. Estimates are based on Black & Veatch project experience, vendor inquiries, and literature review.

For each technology, a "Development Potential" section discusses the potential for development of that technology near Alliant Energy's service territory. The developable potential represents Black & Veatch's estimate of what could be built in the next 5 to 20 years, given constraints on resources, utility integration issues caused by intermittent resources, ability of technology suppliers to meet demand, and available hosts (for co-firing and biofuel applications).

The following characteristics are addressed for each of the renewable energy options:

- Technology descriptions.
- Performance and emissions estimates.
- The following cost estimates (provided in 2013$):
  - Order of magnitude overnight capital cost estimates.
  - Fixed O&M.
  - Variable O&M.
- Construction duration.

In addition, available economic incentives are also summarized for each renewable technology. A detailed discussion of incentives for renewable energy projects is provided in Section 2.5 of this report.

8.1 WIND

Wind power continues to be the fastest growing energy source in the world with an annual growth rate of 17.8 percent over the past five years. Cumulative worldwide wind generating capacity is now estimated to be more than 285,000 MW. In the US, 2012 was a record year with over 13,000 MW of new wind power installed, more than any other country in the world. This was a 12.3 percent increase over 2011 with the US now representing 35.2 percent of the global wind market.

The US wind market has been driven by a combination of the Production Tax Credit (PTC), the Investment Tax Credit (ITC), accelerated tax depreciation, and state mandates. In the past, the PTC has expired and been renewed several times; it was recently extended in January 2013 as part of the American Taxpayer Relief Act. The PTC provides a 10-year, inflation-adjusted credit that was raised from 2.2¢/kWh in 2012 to 2.3¢/kWh in 2013. The ITC, originally introduced through the American Reinvestment and Recovery Act passed in February 2009, was also extended through the

American Taxpayer Relief Act. The ITC allows wind developers to choose to receive a 30 percent tax credit in lieu of the PTC. The ITC can also be converted to a cash grant. Wind power projects that begin construction before the end of 2013 will be eligible to receive the PTC or ITC. Accelerated tax depreciation enables wind project owners to depreciate the vast majority of the investments over a 5 to 6 year period for tax purposes. The American Taxpayer Relief Act extended a 50 percent 1st-year bonus depreciation for qualifying property placed in 2013 (and 2014 for certain long-lived property). State mandates are in place in 29 states and Washington D.C. Many of these mandates were challenged over the past year by opponents of these renewable energy standards, but no state repealed its previously established requirements.

8.1.1 Applications

Wind power systems convert the movement of the air to power by means of a rotating turbine and a generator. While there are alternative designs that have been constructed and placed into service, almost all modern utility-scale wind turbines employ a similar design, as illustrated in Figure 8-1. These turbines are upwind-facing machines with hub heights of 80 to 120 meters and employ three blade rotors and asynchronous (induction) generators. These generators are typically located in the nacelle of the turbine. To regulate the rotational speed of the rotor, modern wind turbines have the ability to adjust the pitch of the blades depending upon the actual wind speed.

Typical land-based, utility-scale wind energy systems consist of multiple wind turbines that range in size from 1 to 3 MW, although the use of single, smaller turbines is also common in the United States for powering schools, factories, water treatment plants, and other distributed loads. Generation capacities for land-based utility scale, wind energy system installations typically range from 50 to 300 MW, with an average project size of approximately 100 MW.

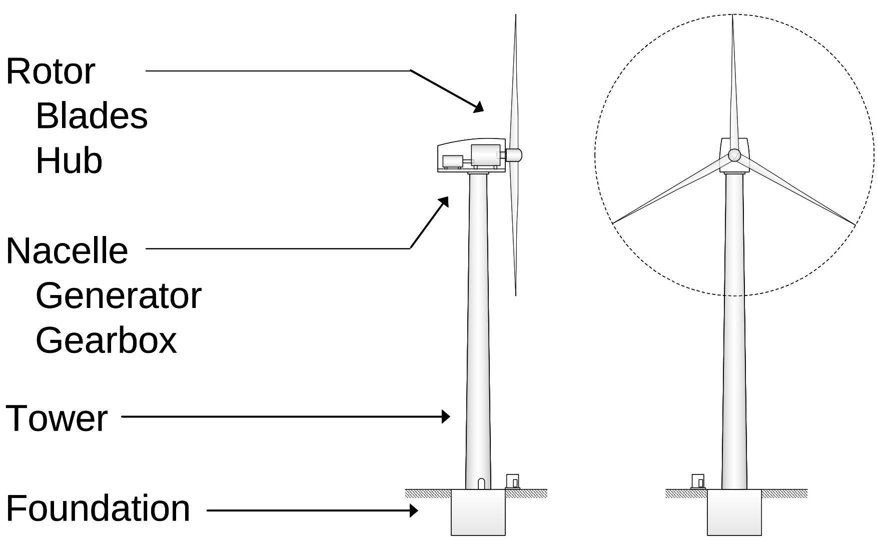


Figure 8-1 Typical Wind Turbine Design

Offshore wind energy projects are being actively developed and built in Europe, and offshore projects are under development in the US with construction expected to begin by the end of 2013 for two projects off the northeastern coast. These offshore projects encourage the development of larger turbines (up to 5 MW) and larger wind farm sizes.

8.1.2 Resource Availability

Turbine power output is proportional to the cube of wind speed, which makes small differences in wind speed very significant. Wind strength is rated on a scale from Class 1 to Class 7, as shown in Table 8-1.

Table 8-1 Wind Power Class Characteristics

WIND POWER CLASS	HEIGHT ABOVE GROUND: 50 M (164 FT) (1)	
	WIND POWER DENSITY (W/M^2) (2)	SPEED (M/S) (2)
1	0 to 200	0 to 5.60
2	200 to 300	5.60 to 6.40
3	300 to 400	6.40 to 7.00
4	400 to 500	7.00 to 7.50
5	500 to 600	7.50 to 8.00
6	600 to 800	8.00 to 8.80
7	800 to 2,000	≥ 8.80

1. Vertical extrapolation of wind speed based on the 1/7 power law, defined in Appendix A of the Wind Energy Resource Atlas of the US, 1991.
2. Mean wind speed is based on Rayleigh speed distribution of equivalent mean wind power density. Wind speed is for standard sea level conditions. To maintain the same power density, wind speed must increase 3 percent per 1,000 m (5 percent per 5,000 ft) elevation.

Figure 8-2 and Figure 8-3 show average annual wind resource maps at 80 meters for Iowa and Minnesota, respectively. In general, the best available winds are at or above the Class 5 category. This includes an area in the western and north-central regions of Iowa extending into southern Minnesota. The surrounding regions in Iowa and Minnesota are comprised of mainly Class 3 and Class 4 winds.

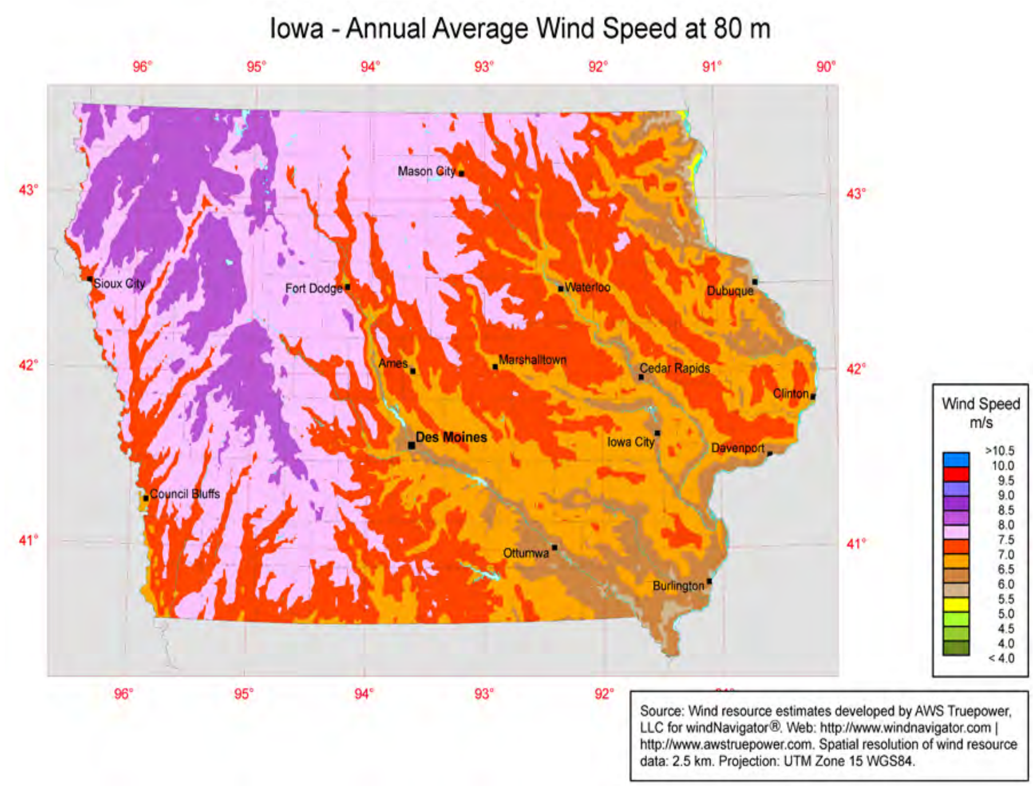


Figure 8-2 Iowa Wind Resource Map[30]

[30] Wind Powering America http://www.windpoweringamerica.gov/wind_resource_maps.asp?stateab=ia

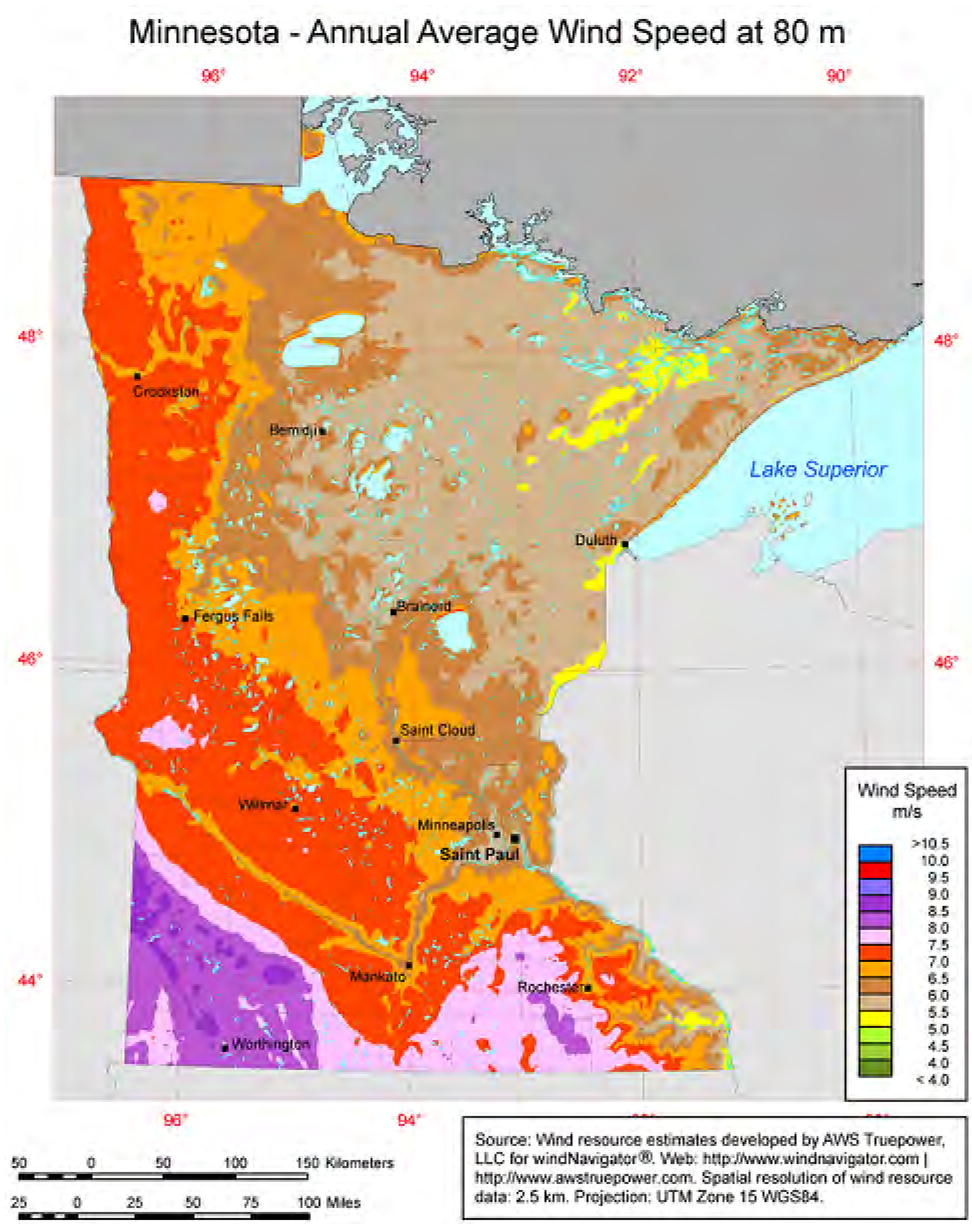


Figure 8-3 Minnesota Wind Resource Map[31]

[31] Wind Powering America, http://www.windpoweringamerica.gov/wind_resource_maps.asp?stateab=mn

8.1.3 Cost and Performance Characteristics

8.1.3.1 Typical US Project

In recent years, wind turbine prices have dropped substantially; at the same time, advances in technology and increases in hub height and rotor diameter size have provided improved operational performance. The drop in turbine prices is a result of fierce competition amongst turbine OEMs and equipment suppliers in addition to reduced demand expectations for the remainder or 2013. Installed project costs in the US also continued to trend lower in 2012. Turbine prices seemed to have peaked in 2008 to 2009 while installed project costs appear to have peaked in 2009 to 2010. For example, a capacity-weighted average installed project cost stood at $2,300/kW in 2009 while in 2012 that average cost for the same capacity dropped to around $1,950/kW. The project costs reflect turbine purchases and installation, balance of plant, and any substation and/or interconnection expenses. Wind projects that require grid upgrades or long transmission tie lines result in substantially higher costs

- After seeing significant gains in identifying and developing sites with better wind resources in the mid-2000s, average capacity factors across the nation have been essentially stagnant since 2005. Although turbine design changes in recent years have been able to significantly boost capacity factors at specific sites, newer wind energy projects are also being built in areas with lower quality resources. As a result, the average capacity factor for all installed wind projects in the United States continues to hover at slightly above 30 percent. However, due to the new turbine technology the maximum capacity factors attained by individual projects in the past few years have exceeded 50 percent on several occasions.

Table 8-2 provides the typical characteristics for a 50 to 100 MW wind farm installed in the US.

8.1.3.2 Representative Projects within Northwest Iowa

Black & Veatch performed a high level wind project siting analysis to identify a suitable development area for a representative project in northwest Iowa. Areas with significant available land for additional development (heavily developed areas were generally excluded) and without known major environmental drawbacks were included in the study. The siting analysis was based on a Geographic Information Systems (GIS) siting model developed to estimate cost and performance characteristics for wind projects in these regions.

Black & Veatch used multiple public and private data sources, including:

- Predicted average wind speed maps from the US Department of Energy (DOE) Wind Powering America web site,
- Elevation from the US Geological Survey (USGS),
- Existing transmission line routes from Ventyx,
- US wind industry cost data from the DOE and Black & Veatch internal databases.

Table 8-2 Wind Technology Characteristics for Typical US Project

	TYPICAL US PROJECT
Typical Duty Cycle	As Available
Net Plant Capacity, MW	50 to 200
CF, percent	30 to 50
Economics, 2013$	
Overnight EPC Cost, $/kW	1,400 to 2,500
Owner's Cost Allowance, percentage of EPC Cost	15
Total Project Cost, $/kW	1,610 to 2,875
Fixed O&M, $/kW-yr	18 to 58
Variable O&M, $/MWh	Included in Fixed O&M
Technology Status	
Commercial Status	Commercial
Installed US Capacity, MW	60,000(1)
Project Duration, NTP to COD, months	12
1. American Wind Energy Association (AWEA), 2nd Quarter 2013 Market Report, July 2013.	

The GIS model estimates project capital cost and net capacity factor for a representative 100 MW wind project in the study area. The level of granularity for the model is a 400 meter square grid. Table 8-3 provides the characteristics for a representative 100 MW wind farm installed in northwest Iowa using the GE 1.7-100 turbine and the Siemens SWT 2.3-101 turbine. Cost and production estimates were calculated for a hub height of 80 meters with a mean wind speed between 8 and 8.5 m/s.

8.1.4 Environmental Impacts

Wind is a clean generation technology from an emissions perspective. However, there are still environmental considerations associated with wind turbines. Opponents of wind energy frequently cite visual impacts and noise as drawbacks. Turbines are exceeding heights of 450 feet, and for maximum capture of resource tend to be located on ridgelines and other elevated topography. Turbines can cause avian and bat fatalities if they are located in areas populated by native birds, nesting bats, or on migratory flyways. To a large degree, these issues can be mitigated through proper siting, rigorous environmental review, and the involvement of the public during the planning process.

Table 8-3 Wind Technology Characteristics for Representative Wind Project in Northwest Iowa

	GE 1.7-100	SIEMENS SWT-2.3-101
Typical Duty Cycle	As Available	As Available
Net Plant Capacity, MW	100	100
Capacity Factor, percent	47	41
Economics, 2013$		
Overnight EPC Cost, $/kW	1,950	1,750
Owner's Cost Allowance, percentage of EPC Cost	15	15
Total Project Cost, $/kW	2,240	2,010
Fixed O&M, $/kW-yr	41	36
Variable O&M, $/MWh	Included in Fixed O&M	
Technology Status		
Commercial Status	Commercial	Commercial
Project Duration, NTP to COD, months	12	12

1. American Wind Energy Association (AWEA), 2nd Quarter 2013 Market Report, July 2013.

8.1.5 Development Potential

Wind energy currently accounts for a large portion of Alliant Energy's generation portfolio. Taking further advantage of the available wind resource could increase this contribution. Iowa and Minnesota currently have the third and seventh largest state total wind power capacities, respectively. As far as percentage of in-state generation is concerned, Iowa continues to lead the way with over 1/4 of the state's power generated by wind. The US DOE's division of Energy Efficiency and Renewable Energy estimates that Minnesota and Iowa have the potential to generate nearly 56,000 and 19,000 MW of wind power, respectively. Already there is more than 8,100 MW of installed wind power generation in Minnesota and Iowa with over 1,000 MW built in 2012.

Transmission, or lack thereof, can be a barrier to new wind power development. New transmission is important for wind energy because wind projects are located in areas with sufficient wind resource and these areas are often far away from load centers. In December 2012, Midcontinent Independent System Operator (MISO) approved its Transmission Expansion Plan 2012. This plan includes nearly 600 transmission projects representing over 6,000 circuit miles of new or upgraded transmission lines to complement the existing lines in the region.

8.2 SOLAR

There are two primary groups of solar technologies: solar PV and solar thermal. Solar PV works by converting sunlight directly into electricity. Solar thermal works by absorbing the energy of the sunlight and making use of the heat generated.

Solar PV utilizes global insolation, which is the vector sum of the direct and the diffuse components of insolation. The power produced depends on the intensity of the solar radiation incident on the cell and on the materials that form the solar cells.

Solar PV cells and modules presently employed for solar power applications typically fall into one of the following categories:

- Crystalline silicon
  - Monocrystalline silicon
  - Polycrystalline silicon
- Thin-film

Crystalline silicon cells are widely used in PV applications. Thin film modules, while less expensive but less efficient than crystalline modules, are also an option for large scale solar applications. The commercially available thin film technologies are based on amorphous silicon (a-Si), cadmium telluride (CdTe), or copper indium gallium (di) selenide (CIGS) alloys as the photovoltaic material.

Solar PV panels generate direct current (dc) electricity, and an inverter is employed to provide alternating current (ac) electricity to the local electrical grid. Like wind energy technologies, PV technologies are intermittent generators. Average capacity factors range from 10 to 25 percent. If batteries or other storage technologies are coupled with solar PV systems, the intermittency of the solar power output may be smoothed.

Large scale solar thermal for electrical energy generation is referred to as concentrating solar power (CSP). The primary types of CSP technologies include:

- Parabolic trough
- Central receiver
- Linear Fresnel
- Dish Stirling

In these applications, the solar radiation is focused by mirrors or other reflective surfaces onto a receiver. In the receiver, a thermal fluid is heated and then used to produce steam which drives a turbine or engine. CSP plants are more dependent on the direct normal insolation (DNI) component, which is that portion of the sunlight traveling in a direct trajectory from the sun to the object, without being significantly dispersed. CSP plants have the additional capability of incorporating thermal energy storage. Thermal storage allows the plant to generate for more hours of the day, instead of just when solar insolation is available.

Due to the thermal inertia of the working fluid, even without thermal storage, CSP plants are less sensitive to the solar resource intermittency than PV plants. Typical capacity factors for CSP plants in favorable locations can be up to 40 percent. The capacity factor of an installation depends on the insolation incident upon the area and the energy capture characteristics of the solar energy collection systems. Capacity factor directly affects economic performance; thus, reasonably high insolation is required for cost-effective installations. Without energy storage systems, solar technologies cannot be relied upon as firm capacity for peak power demands.

Solar PV technologies are discussed in detail in Section 8.2.1, while CSP technologies are discussed in detail in Section 8.2.2.

8.2.1 Solar Photovoltaic Technologies

Historically, PV systems have been employed for small distributed applications, while CSP systems have been utilized for large, central station applications. This perspective has shifted, however. In recent years PV systems have increased significantly in size. A 250 MW PV system was installed in Yuma County, Arizona in 2012, and multiple PV projects with net generation capacities in the range of 100 to 500 MW are under construction in the southwest United States.

PV module production has increased significantly over the years, reaching a worldwide module production output greater than 70 GW in 2012.[32] Worldwide grid-connected residential and commercial installations grew from 173 MW in 2000 to 28 GW in 2012, with a total grid-connected worldwide capacity of more than 90 GW.[33] Within the United States, 3.3 GW of grid-connected PV was installed in 2012, bringing the cumulative installed capacity to approximately 7.2 GW.

8.2.1.1 Operating Principles

PV systems convert sunlight directly into electricity, and the conversion of sunlight into electricity is known as the PV effect. The power produced depends on the material involved, the intensity of the solar radiation incident on the cell, and the cell temperature. Crystalline silicon cells are most widely used today. Monocrystalline cells are manufactured by growing single crystal ingots, which are sliced into thin cell-sized wafers. The production of polycrystalline cells requires a less strict manufacturing process than monocrystalline cells, with some reduction in cell efficiency. Thin film modules, which are less expensive but not as efficient, are also being used for large scale solar applications.

Critical components of a PV system are the PV modules, inverters, and racking system. The other important components include combiner boxes, disconnect switches, meters, and monitoring equipment. In a grid-tied solar PV system, the solar modules convert sunlight directly into dc power, and the inverter converts the dc power from the modules into grid-quality ac power used by the electric grid. These critical components are discussed in more detail as follows.

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[32] "Solar Market Insight Report 2012," *Solar Energy Industries Association,* available at http://www.seia.org, accessed July 2013.

[33] "A Snapshot of Global PV 1992-2012," *IEA Photovoltaic Power Systems Program,* available at http://www.iea-pvps.org, accessed July 2013.

Solar Modules

Solar modules comprise individual solar cells connected electrically in series. The cells are then encased with an encapsulant and mounted in a rectangular frame, situated behind a glass that is designed to withstand hail and other impacts. There are two predominant types of flat plate solar PV module technologies on the market: crystalline silicon and thin film.

Crystalline silicon modules consist of an array of solar cells interconnected in series. The manufacturing process of cells comprises a rather complex set of steps, involving sawing thin wafers of extremely pure silicon ingots, exposing the wafer to chemical and physical treatments, and finally adding a metallic conducting mask and an anti-reflective coating that creates the distinctive dark metal blue color of the cells. The manufacturing of crystalline silicon modules is a highly automated and energy intensive process.

Crystalline silicon can be grown in two main forms: monocrystalline silicon and polycrystalline silicon. Monocrystalline silicon has an ordered crystalline structure with each atom arranged in a regular pattern; because of this arrangement, these cells have relatively high efficiencies of approximately 20 percent. The structure of polycrystalline cells is less ordered, which reduces production costs but also reduces cell efficiencies to approximately 14 percent.

Thin film modules are manufactured by depositing thin layers of semiconductors on a sheet of glass. Thin film solar cells are made from layers of semiconductor materials only a few micrometers thick; hence the term, "thin film." This process eliminates the energy intensive ingot growth and wafer sawing steps that are required for crystalline silicon modules. This streamlined manufacturing process and the drastic reductions in semiconductor raw material give thin film technologies a cost advantage. Currently, most thin-film modules are of two types: Cadmium Telluride (CdTe) and Copper Indium Gallium Selenide (CIGS). CdTe and CIGS manufacturers target efficiencies near 13 percent.

Solar PV modules have a design life of 20 to 30 years. There have been crystalline silicon systems operating for more than 20 years, and current modules have higher quality glass and encapsulant than older ones. Solar modules can be expected to degrade in performance over time, between 0.5 and 1 percent each year. Most solar PV modules carry a 20 to 25 year warranty, which usually covers modules that run at 90 percent of minimum power at 10 years and 80 percent at 20 or 25 years. Manufacturers generally warrant the modules to minimum power, not rated power. Therefore, a 200 watt module with a 5 percent power tolerance is warranted to 80 percent of its minimum power of 190 watts, or 152 watts.

Inverters

The inverter is a critical component in photovoltaic (PV) power systems. The main function of this device is to convert the dc power generated by the PV modules to grid quality ac power. Modern inverters include advanced electronics that enable fine control of the conversion process as well as a wide range of other features such as continuous monitoring of internal system and grid parameters. The electronics for large scale inverters also include data acquisition, telemetry and other supervisory and control functions. Inverters must comply with several international standards in order to meet safety and performance requirements for commercial use

In solar systems, inverters perform the following functions:

- Convert the dc electricity from the modules to ac electricity used by the grid.
- Perform maximum power point tracking to ensure each string is performing at its maximum power.
- Step up array voltage to grid voltage.
- Provide a data interface for monitoring systems to log and track generation.
- Provide “anti-islanding” protection in accordance with IEEE Standard 1547, which ensures the inverter will disconnect from the grid if it senses the loss of grid power.

With the recent increase in solar PV capacity on the grid, additional functions have been proposed for the inverters to improve grid stability, including low voltage ride-through (LVRT) and reactive power control. LVRT manages inverter operation when the voltage on the grid is temporarily reduced by a fault or load change in the grid. During and after the voltage drop, the inverter may be required to disconnect temporarily from the grid, and then reconnect and continue operation after the voltage drop. Alternatively, it may be required to stay connected and support the grid with reactive power.

Reactive power, often referred to as VARs, represents the power consumed by the reactive load when there is a phase difference between the applied voltage and the current. Reactive power control is used to minimize VARs by balancing capacitive and inductive loads.

Other inverter architectures are available, such as micro-inverters. Micro-inverters can be connected directly to the module, either by the module manufacturer or a system integrator, which eliminates much of the dc wiring and simplifies installation of small solar PV systems. Microinverters have become widely used by residential installers because they simplify wiring, reduce inventoried equipment and often carry 25 year warranties.

Due to heat dissipation or internal power (needs for fans and electronics), inverters are not 100 percent efficient at converting power. Most utility scale inverters have a maximum efficiency of 97 to 98 percent.

The design life of utility scale inverters is 20 to 25 years. Manufacturers generally offer 5 year limited warranty for these inverters, with an option to extend the warranty in increments of 5 years to 10, 15, and 20 years. Utility scale inverters may be refurbished. Fans and capacitors may need to be replaced in a major overhaul. Black & Veatch typically assumes a major overhaul of inverter components would be carried out by the inverter OEM at year 13 of the inverter’s lifetime, with an estimated cost of approximately one fourth of the initial cost of the inverter (in present value dollars). This cost (on an annualized basis) is included in the Consolidated O&M costs estimated by Black & Veatch.

Mounting Systems

The racking system provides the mechanical support for the modules. Racking systems have incorporated several features in an effort to maximize the power produced by the solar array per dollar invested in the system. Solar PV systems of different mounting configurations (i.e., fixed tilt or tracking) will produce different hourly generation curves and have different associated costs and revenues.

Utility scale PV installations are ground mounted and are built with racking systems at a fixed orientation and tilt or on one or two axis trackers. A flat plate module (the most typical form factor used in utility scale systems) achieves the highest operating point when the cells are normal to the sun. Therefore, the output of the system depends on the amount of irradiance to which the PV module is exposed. Several factors determine the amount of energy a PV system will generate, including the angle between the position of the module and the sun's path throughout the day and throughout the year, as well as the climatic conditions.

A fixed tilt system will limit the normal exposure of the modules to the sun path, whereas a rotating system (in one or two axes) will increase the exposure of the modules to the solar radiation. Typically, a one-axis tracker rotates east to west, following the daily sun path throughout the horizon. A dual-axis tracker follows the sun path throughout the day, both on the east to west and elevation trajectory. Modules mounted on dual-axis trackers are continuously facing the sun at a normal angle. The amount of energy generated by a system using dual-axis trackers will be more than a system using one-axis trackers which, in turn, will be higher than a fixed tilt system. The difference in the amount of energy is determined by the environmental conditions of the specific location. In the arid regions of the southwest United States, horizontal, one-axis trackers can generate approximately 20 percent more energy than a fixed tilt system on an annual basis, while a dual-axis tracker can generate approximately 35 percent more energy than a fixed tilt system on an annual basis. This performance comes at a cost, however, as the dual axis tracking systems use more land area and are more costly to install and maintain than single axis or fixed tilt systems. Depending on site-specific parameters, the increase in energy production may justify the higher installation and maintenance costs.

In recent years there has been significant effort put into the design of racking systems that speed installation times in the residential, commercial, and utility markets. These design improvements have become a significant part of the marketing of PV racking systems.

8.2.1.2 Applications

Solar PV was originally developed as a power source for space applications. The modularity, simple operation, and low maintenance requirements of solar PV make it ideal for serving distributed, remote, and off-grid applications. PV found its first terrestrial uses in remote industrial and residential applications. This off-grid use of solar has been cost-effective for some time, since it is generally less expensive than extending the electricity grid to remote locations. While these off-grid installations were roughly half the worldwide PV market in 1999, the explosive growth of "grid-tied" PV had reduced its share of the total PV market to less than 10 percent by

2012.[34] Historically, most PV applications were in the kW range. However, large, utility-scale installations have quickly gained prevalence. There are hundreds of PV systems worldwide with capacities greater than 1 MW. The largest systems are in the hundreds of MW range, including the 250 MW Agua Caliente solar plant in Yuma County, Arizona. Facilities with a total net generation output in excess of 500 MW are currently under construction in California.

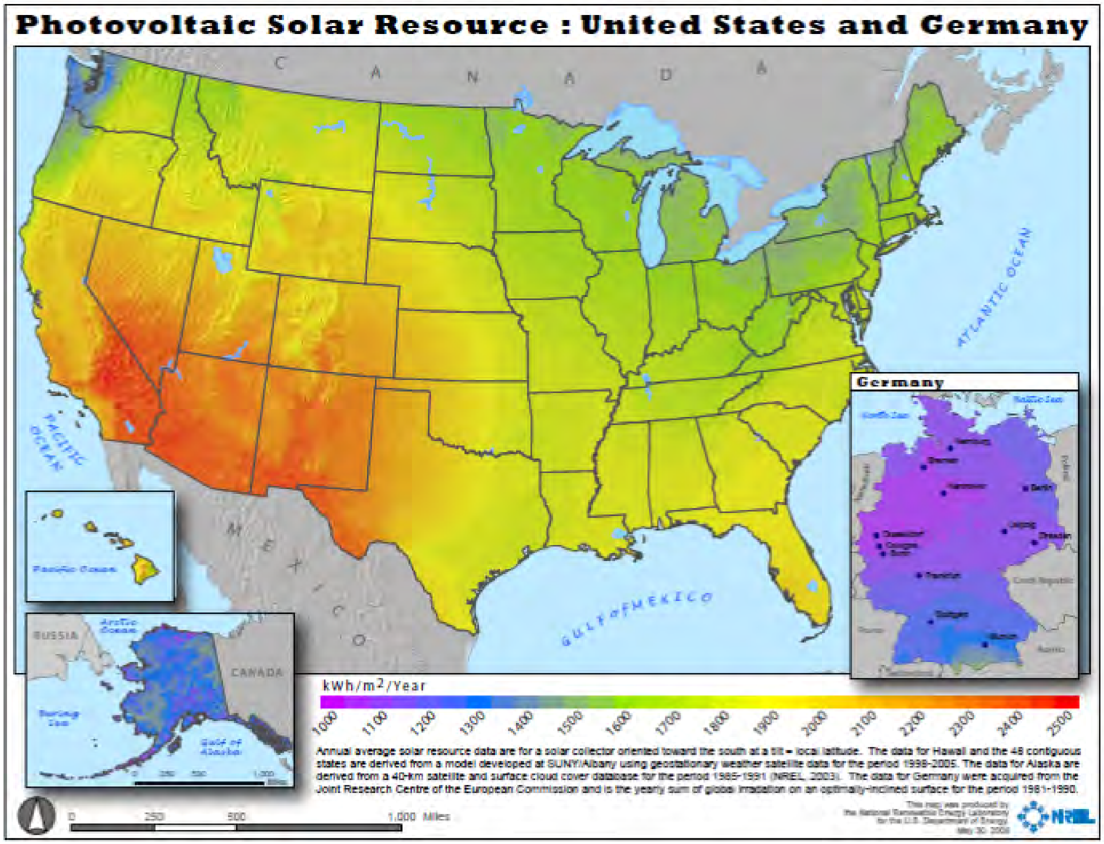
8.2.1.3 Resource Availability

Solar insolation reaching the earth's surface has two components: DNI and diffuse. DNI typically comprises about 80 percent of the total insolation reaching an object normal to the sun path in the horizon. The DNI is the component of the sunlight that travels in a direct path from the sun to the object on the earth's surface. Diffuse insolation is the component of the sunlight that reaches an object after being scattered by the atmosphere. In addition, sunlight reflected off the ground or other surfaces and reaching an object is referred to as albedo. On a cloudy day, all radiation is diffuse. The vector sum of DNI and diffuse insolation is termed global horizontal irradiance (GHI), which is the sum of all irradiance observed by a flat plane (there is no albedo on a horizontal surface). CSP systems are highly dependent on DNI, while non-concentrating PV systems use GHI. Regions with minimum cloud coverage, such as the southwest United States, offer the greatest solar concentrator potential. Because PV systems use global insolation, the siting of these systems is much more flexible.

A general feature of solar energy technologies in Northern latitudes (like in the United States) is that peak output typically occurs on sunny summer days. In general, this coincides with periods of higher electrical demand.

The PV market installations in the United States have grown in recent years. The United States installed approximately 3,300 MW in 2012 (up from 293 MW installed in 2008), or about half of the 7,600 MW installed in Germany during the same period. Germany has been one of the world leaders in PV installations for several years due to an aggressive feed-in tariff, in which utilities pay a higher price for electricity generated by PV. The German feed-in tariff (FIT) has been steadily reduced over the years, but 2012 was still a record year for PV installations. With significantly reduced tariffs, the German government is targeting 4 GW of PV to be installed in 2013. As shown in Figure 8-4, Germany's solar resource is not as strong as that found in the Alliant Energy service territory. While still not as strong as the southwest United States, the solar resource in Alliant Energy's service territory is still sufficient to support solar PV development.

[34] "Solar PV Technology Roadmap¸" *International Energy Agency*, available http://www.iea.org, accessed July 2013.

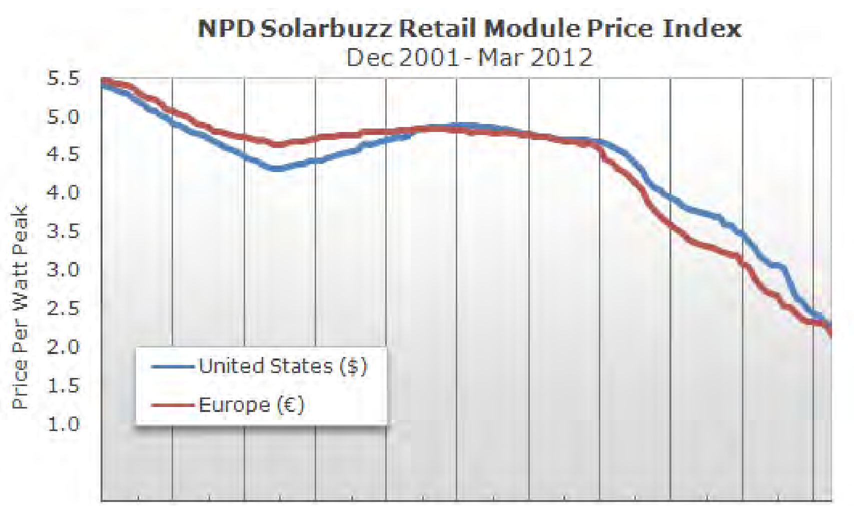


(Source: NREL)

Figure 8-4 Solar PV Resource for the US vs. Germany

8.2.1.4 Cost and Performance Characteristics

Over the past 30 years, costs of solar PV modules have declined significantly as improved technology and manufacturing economies of scale have reduced costs. Solar PV module costs were roughly $10 per watt in 1985; today, module costs in the United States (for bulk purchases by PV installers) are less than $1 per watt. Module costs represent a significant portion the total cost of a system, about one third for large scale systems, so solar installations are especially sensitive to movement in module pricing. Figure 8-5 shows retail module prices over the past from 2001 to 2012. Note that these prices represent published retail costs, not bulk purchase costs available to PV installers.



(Source: Solarbuzz, accessed July 2013)

Figure 8-5 US Module Costs, $/Watt

Table 8-4 presents cost and performance characteristics of a solar PV system at two locations (i.e., Waterloo, Iowa and Madison, Wisconsin). The solar PV system is assumed to be a 10 MWac fixed tilt, polycrystalline silicon system. These characteristics are expected to be representative of systems installed at sites within the Alliant Energy service territory. The full design basis and modeling results for these solar PV scenarios are presented in Appendix B.

Table 8-4 Solar PV Technology Characteristics

	WATERLOO, IA	MADISON, WI
Performance		
Typical Duty Cycle	As Available, Peaking	As Available, Peaking
Net Plant Capacity,(1) MW	10	10
Estimated Energy Production, MWh/yr	17,960	17,650
CF,(2) percent	20.5	20.1
Economics (2013$)		
Overnight EPC Cost, $/kW (3)	2,500 to 3,000	
Owner's Cost Allowance, percentage of EPC Cost	12	
Total Project Cost, $/kW (3)	2,800 to 3,360	
Fixed O&M, $/kW-yr	23 to 42	
Variable O&M, $/MWh	Included as Fixed O&M	
Technology Status		
Commercial Status	Commercial	
Installed US Capacity, MW	7,200 (4)	
Project Duration, NTP to COD, months	12	

Notes:
1. All capacities are ac.
2. Represents the ac CF.
3. Represents the EPC cost on a $/kWac basis.
4. Grid connected, end of 2012 (Source: IEA-PVPS).

8.2.1.5 Environmental Impacts

A key attribute of solar PV cells is that they have virtually no emissions after installation. Some thin film technologies have the potential to discharge heavy metals during manufacturing; however, this issue is being adequately addressed through proper monitoring and control. These impacts are generally inconsequential compared to emissions from conventional fossil fuel technologies. In addition, solar PV has little water requirement at the generation source.

8.2.1.6 Development Potential

There is approximately 17 MW of total solar PV capacity in the combined states of Iowa, Minnesota, and Wisconsin.[35] Moderate solar resource and the historically higher capital costs resulting in high annual costs of energy has limited development. However, as capital costs have dropped, solar PV has potential to be a viable option for electricity generation in the Alliant Energy service territory.

A five year, Iowa-based PV study previously completed indicated positive results with fixed-tilt PV modules and concluded that the solar resource in central Iowa "is sufficient for practical solar energy systems."[36] In 2012, Iowa enacted limited personal and corporate tax credits to incentivize solar installations. In June 2013, Minnesota adopted a solar energy standard with several features to grow the state's solar PV market, including a 1.5 percent solar standard for some investor-owned utilities.

8.2.2 Solar Thermal Technologies

Solar thermal technologies (also referred to as CSP technologies) convert the sun's energy to electricity by capturing heat. Technological advances have expanded the applications of solar thermal to a utility scale. The leading technologies currently include parabolic trough and central receiver (i.e., power tower), although linear Fresnel and dish Stirling applications have been proposed in the recent past. With adequate solar resources, solar thermal technologies are appropriate for a wide range of intermediate and peak load applications, including central station power plants and modular power stations in both remote and grid-connected areas.

8.2.2.1 Operating Principles

Most solar thermal systems (parabolic trough, central receiver, and linear Fresnel) transfer the energy received from solar insolation to a heat transfer fluid, typically a molten salt or heat transfer oil. A steam generator then converts the energy in the heat transfer fluid to steam, which is subsequently used to power a turbine. A thermal storage system can be used to store hot heat transfer fluid, providing thermal energy storage. By using thermal storage or by combining the solar system with a fossil fired system (a hybrid solar/fossil system), a solar thermal plant can provide dispatchable electric power.

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[35] National Renewable Energy Laboratory, Open PV Project Database, http://openpv.nrel.gov, accessed June 2013.
[36] Solar-Case Studies and Projects, Iowa Energy Center, http://www.energy.iastate.edu/renewable/solar/cs-index.html, accessed January 2010.

8.2.2.2 Applications

Of the four technologies, parabolic trough (refer to Figure 8-6) represents the vast majority of installed capacity, primarily in the southwest United States. There are nine Solar Electric Generating Station parabolic trough plants in the Mojave Desert, with a combined capacity of 354 MW. These plants were installed between 1985 and 1990 and have been in continual operation since that time. The other operating parabolic trough plants in the United States are a 64 MW plant in Nevada and a 75 MW integrated solar combined cycle system in Florida. Most of the major parabolic trough developers are pursuing projects in the Southwest, where more than 1,200 MW of parabolic trough and power tower systems are currently under construction.

In Spain, there is more than 2,000 MW CSP operating, and many of these systems have thermal storage. However, there have been modifications and taxes imposed on existing CSP FIT agreements, and the current operating status of many of these plants is not known. In 2012, the CSP FIT was canceled for new plants beyond a 2,355 MW cap. Other countries with large CSP projects currently under construction include India and South Africa.

Figure 8-6 Parabolic Trough Installation

There are currently no commercial molten salt power tower plants in operation in the United States. However, SolarReserve's Crescent Dunes Project is currently under construction in Nevada. This 110 MW project is planned to have 10 hours of thermal energy storage. In 2007 and 2009, respectively, two water/steam power towers (PS-10 and PS-20, as shown on Figure 8-7) began operating in Spain, and in 2011, the 20 MW Gemasolar molten salt system began operating.

A somewhat recent development in power tower technology is the advent of distributed power towers, also sometimes referred to as "mini" power towers. These systems employ smaller heliostats and shorter towers than the classical approach. Pilot plants with this technology have been built in the United States and Israel, and larger projects are in development, including BrightSource Energy's 380 MW Ivanpah Project that is currently under construction in California.

Figure 8-7 Central Receiver Installation

There are no commercial installations of dish Stirling systems (illustrated on Figure 8-8). Stirling Energy Systems (SES) installed six test units at Sandia National Laboratory in May 2005. In September 2009, SES began construction on a 1.5 MW system near the existing Salt River Project (SRP) Agua Fria power plant in Peoria, Arizona. This project, the Maricopa Solar Plant, was completed in early 2010 and after SES filed Chapter 7 bankruptcy.[37] Another demonstration project is under construction at the Tooele Army Depot in Utah.

[37] Phoenix Business Journal, "Former Stirling power plant in Peoria to be sold, disassembled" Updated March 28, 2012. Accessed online at: http://www.bizjournals.com/phoenix/news/2012/03/27/former-stirling-power-plant-in-peoria.html?page=all.

(Source: Stirling Energy Systems)

Figure 8-8 Parabolic Dish Receiver

Linear Fresnel collectors, shown on Figure 8-9, use a ground-mounted array of long, narrow, flat tracking mirrors to focus the sun's radiation on a linear receiver pipe located above the array. Ausra, a wholly owned subsidiary of AREVA, is the only company that has developed compact linear Fresnel reflector (CLFR) technology in commercial operation. The 3 MW Liddel plant was Ausra's first generation CLFR system, and it is located in New South Wales, Australia. A 44 MW CLFR addition to the 750 MW Kogan Creek coal plant is under development in Queensland, Australia. In the United States, there is one operational CLFR with an installed capacity of 5 MW. In Spain the first, 1.4 MW phase of a 31.4 MW CLFR plant has been operational since 2009, and phase two commenced operation in 2012.

Figure 8-9 Linear Fresnel Demonstration Unit

8.2.2.3 Resource Availability

As discussed previously, solar thermal systems use only DNI, while nonconcentrating systems (like PV) use global insolation. Lower latitudes with minimum cloud coverage offer the greatest concentrating solar potential. Average annual DNI within Alliant Energy's service territory is generally 4.0 kW/m^2/day or less, according to NREL data. Some locations in the southwest United States (where CSP plants are currently located) have DNI as high as 8.5 kW/m^2/day.

A general feature of solar thermal systems and solar technologies is that peak output typically occurs on summer days when electrical demand is high. Solar thermal systems with storage allow dispatch that can improve the ability to meet peaking requirements.

8.2.2.4 Cost and Performance Characteristics

Representative characteristics for parabolic trough (with and without storage) and central receiver technologies are presented in Table 8-5. It should be noted that these characteristics are representative of a more typical location for solar thermal technologies, not necessarily based on a location within the Alliant Energy service territory. Characteristics for a representative parabolic dish and linear Fresnel systems are not available.

8.2.2.5 Development Potential

There is relatively poor potential to develop CSP projects within the Alliant Energy service territory. Currently, there are no significant solar thermal-to-electric operations in the region. The direct solar resource in the Alliant Energy service region is relatively low. The poor resource in Alliant Energy's service area makes solar thermal-to-electric development unattractive.

Table 8-5 Solar Thermal Electric Technology Characteristics

	PARABOLIC TROUGH		CENTRAL RECEIVER
Performance			
Typical Duty Cycle	Intermediate	Peaking	Intermediate-Peaking
Net Plant Capacity, MW	100	100	100
Integrated Storage, hours	6	0	6
CF, percent	30 to 40	20 to 28	35 to 40
Economics, 2013$			
Overnight EPC Cost, $/kW (1)	7,200 to 8,000	5,000 to 5,600	5,000 to 9,000
Owner's Cost Allowance, percentage of EPC Cost	15	15	15
Total Project Cost, $/kW (3)	8,280 to 9,200	5,750 to 6,440	5,750 to 10,300
Fixed O&M, $/kW-yr	65 to 70	55 to 70	80 to 85
Variable O&M, $/MWh	Included in Fixed O&M		
Technology Status			
Commercial Status	Commercial		Commercial
Installed US Capacity, MW	490		124 (2)
Project Duration, NTP to COD, months	24		24

1. Capital cost estimates vary widely. Projects incorporating thermal energy storage would be towards the higher side of the estimates.
2. At present, the installed capacity for Central Receiver technology is represented by the online portion of the Ivanpah Solar Electric Generating System (SEGS). Ivanpah Unit 1 provides 124 MW of net generation capacity; Ivanpah Units 2 and 3, currently under construction, will each provide an additional 126 MW of generation capacity upon their commissioning.

8.3 SOLID BIOMASS

Biomass is any material of recent biological origin. The most common biomass fuel for power applications is wood, although biomass fuels may include crop residues such as corn stover or energy crops such as switchgrass. Solid biomass power generation options include direct-fired and co-fired biomass. This study includes discussion of biomass combustion as well as biomass gasification for the utilization of solid biomass fuels. Direct combustion processes are employed for nearly all the world's biomass power facilities, while biomass gasification technologies are generally not economically competitive with direct combustion options. Advanced biomass gasification concepts, such as biomass integrated gasification combined cycle (BIGCC) and plasma arc gasification, have some potential advantages when compared to conventional combustion technologies, such as increased efficiency and the ability to handle problematic waste materials. However, these advanced biomass gasification concepts have not yet been technically demonstrated at commercial scales and have considerably higher capital costs than biomass combustion technologies.

Solid biomass power generation options include direct-fired biomass, co-fired biomass, and BIGCC, as described in the remainder of this section.

8.3.1 Direct Fired

According to the US DOE, there is about 35,000 MW of installed biomass combustion capacity worldwide and approximately 7,000 MW of installed capacity in the United States.[38] In the United States, combined heat and power applications in the pulp and paper industry comprise the majority of this capacity.

8.3.1.1 Operating Principles

Direct biomass combustion power plants in operation today use the same steam Rankine cycle that was introduced commercially approximately 100 years ago. In many respects, biomass power plants are similar to coal plants. Using heat generated from the combustion of biomass, pressurized steam is raised in a boiler and then expanded through a turbine to produce electricity. Prior to combustion in the boiler, the biomass fuel may require some processing to improve the physical and chemical properties of the feedstock. Conventional boiler designs may be employed for the combustion of biomass, including spreader stoker boilers, fluidized bed boilers, cyclone boilers, suspension burners, and pile burners. Newly constructed biomass-fired generation facilities would likely employ either a stoker boiler or a fluidized bed boiler.

8.3.1.2 Applications

Although wood is the most common biomass fuel for the production of electricity in the United States, other biomass fuels include agricultural residues such as corn stover, wheat straw, dried manure and sewage sludge, black liquor, and dedicated fuel crops such as fast growing grasses and eucalyptus.

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[38] US Department of Energy, Oak Ridge National Laboratory, "Biomass Frequently Asked Questions," available at http://bioenergy.ornl.gov/faqs/index.html.

Biomass plants usually have a capacity of less than 100 MW because of the dispersed nature of the feedstock and the large quantities of fuel required. As a result of the smaller scale of plants and lower heating values of the fuels, biomass plants commonly have lower efficiencies than modern fossil fuel (i.e. coal-fired) plants. In addition to being less efficient, biomass is generally more expensive than conventional fossil fuels on a $/MBtu basis because of added transportation costs. These factors usually limit the use of direct-fired biomass technology to inexpensive biomass sources (e.g., urban wood waste or mill residues).

8.3.1.3 Resource Availability

To be economically feasible, dedicated biomass plants are typically located either at the source of a fuel supply (such as a sawmill) or within 50 miles of numerous suppliers. (It is noted that some facilities source biomass fuels from up to 200 miles away for a very high quantity, low cost supply.) Wood and wood wastes are the primary biomass resources and are typically concentrated in areas of high forest-product industry activity. In rural areas, the production and processing of agricultural crops may generate significant residues that may be collected and fired in biomass plants. These agricultural residues include bagasse, corn stover, rice hulls, wheat straw, and other residues. Energy crops, such as switchgrass and short rotation woody crops, have also been identified as potential biomass sources. In urban areas, biomass resources typically include wood wastes such as construction debris, pallets, yard wastes, and tree trimmings.

In general, the availability of sufficient quantities of biomass is less of a feasibility concern than the high costs associated with transportation and delivery of the fuel. A biomass plant would be limited in capacity by the amount of resource that could feasibly be delivered. A reasonable estimate for this limit is 30 MW to 75 MW depending on the location. Also influencing the size of a biomass plant is the limit on Modified Accelerated Cost Recovery rules which limits accelerated, 5-year, 200 percent declining balance treatment to biomass plants of 80 MW or less.

A 35 MW biomass power plant firing woody biomass would require approximately 1,100 wet tons per day (40 percent moisture content) of woody material or approximately 324,600 wet tons per year (tpy) based on an 80 percent capacity factor. On a dry ton basis, a 35 MW biomass power plant would require approximately 194,000 dry tpy of woody biomass.

8.3.1.4 Cost and Performance Characteristics

Table 8-6 presents the typical characteristics of a 35 MW stoker boiler biomass plant with Rankine cycle using wood waste as fuel.

Two fuel costs scenarios were evaluated. The first was a relatively lower cost ($2.00/MBtu) scenario which would be based primarily on urban wood waste sources in the major metropolitan areas. The second was a moderate cost ($3.50/MBtu) scenario which would be more representative of a project using forest thinnings and forestry residues. Actual fuel cost could vary significantly from the values characterized here. Another possible biomass fuel is dedicated energy crops, which are grown specifically to provide feedstock for biomass plants. However, experience with energy crops is very limited; furthermore, costs for these fuels may approach $5.00/MBtu or greater.

Table 8-6 Direct-Fired Biomass Combustion Technology Characteristics

	35 MW BIOMASS-FIRED COMBUSTION
Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity, MW	35
Net Plant Heat Rate, Btu/kWh (HHV)	13,250
CF, percent	80 to 90
Economics, 2013$	
Overnight EPC, $/kW	5,000 to 5,400
Owner's Cost Allowance, percentage of EPC Cost	25
Total Project Cost, $/kW (3)	6,250 to 6,750
Fixed O&M, $/kW-yr	140 to 150
Variable O&M, $/MWh	9 to 12
Fuel Cost, $/MBtu	2.00 to 3.50(1)
Applicable Incentives	Open loop: $11/MWh PTC(2), 5-yr MACRS Closed loop: $23/MWh PTC(2), 5-yr MACRS
Technology Status	
Commercial Status	Commercial
Installed US Capacity, MW	7,000
Project Duration, NTP to COD, months	36

Notes:

1. Lower fuel cost scenario ($2.00/MBtu) assumes fuel supply consists primarily of urban wood waste sources in major metropolitan areas; it is estimated that these fuels would have a moisture content of approximately 20% and a higher heating value of approximately 6,800 Btu/lb. Higher fuel cost scenario ($3.50/MBtu) scenario assumes fuel supply consists primarily of forest thinnings and/or forestry residues; it is estimated that these forest-based fuels would have a moisture content of approximately 40% and a higher heating value of approximately 5,100 Btu/lb.
2. The duration of the eligibility period for the PTC is 10 years after the date the facility is placed in service.

The heating value of the biomass fuels depends on the moisture content of the fuel. On a dry basis, nearly all biomass fuels have a heating value of approximately 8,500 Btu/lb. Urban wood waste fuels typically have moisture contents in the range of 15 percent to 40 percent, and as-received heating values of these fuels would have a corresponding range of 5,100 Btu/lb (at 40 percent moisture content) to 7,200 Btu/lb (at 15 percent moisture content). Forest thinnings and forest residues typically have moisture contents in the range of 40 percent to 55 percent. Considering this range in moisture content, the as-received heating value of these fuels would range from 3,800 Btu/lb (at 55 percent moisture content) to 5,100 Btu/lb (at 40 percent moisture content). Assuming a heating value of approximately 5,100 Btu/lb, a net plant heat rate of 13,250 kWh/Btu is considered to be appropriate for screening-level analyses of biomass combustion options.

8.3.1.5 Environmental Impacts

Environmental benefits may help make biomass an economically competitive fuel. Unlike fossil fuels, biomass may be viewed as a carbon-neutral power generation fuel. While CO_2 is emitted during biomass combustion, a nearly equal amount of CO_2 is absorbed from the atmosphere during the biomass growth phase. Biomass fuels contain little sulfur compared to coal and, therefore, produce less SO_2. Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals such as mercury, cadmium, and lead. However, biomass plants still must include technologies to control emissions of pollutants similar to large coal plants. Primary pollutants are NO_x, PM, and CO. Commercially available air quality control technologies are used to manage these pollutants.

Biomass plants are considered to be stationary sources of air emissions and must adhere to relevant air quality regulations, as administered by the US Environmental Protection Agency (US EPA) and appropriate regulatory agencies within the state in which the project is located. Under these regulations, emissions of various flue gas constituents are limited to permitted levels that may or may not require the installation of air quality control (AQC) systems. The permitted levels of emissions are dependent upon the classification of the facility with respect to rules and regulations for both "criteria pollutants"[39] and hazardous air pollutants,[40] or HAPs. Like other stationary emission sources (e.g., coal-fired boilers and natural gas-fired combustion turbines), a biomass project may be classified as either a "major source" or as a "minor source" for criteria pollutants and HAPs.

Standards and requirements associated with criteria pollutants are commonly referred to as Best Available Control Technology (BACT) requirements, while standards and requirements for HAPs are commonly referred to as Industrial Boiler Maximum Achievable Control Technologies (IB MACT) requirements.

The determination of whether a specific biomass project is classified as a major or minor source with respect to BACT and IB MACT requirements depends upon several parameters, including:

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[39] Under the Clean Air Act Amendments of 1990 (CAAA), criteria pollutants regulated by the US EPA include nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), and particulate matter (PM_{10} and $PM_{2.5}$), ozone and lead (Pb). Volatile organic compounds (VOCs) are considered surrogates for ozone and are also regulated.

[40] HAPs are pollutants that are known or suspected to cause cancer or other serious health effects. Under HAP regulations, regulated constituents include dioxins/furans, mercury (Hg), carbon monoxide (as a surrogate for non-dioxin/furan organic HAPs), hydrochloric acid (HCl, as a surrogate for acid gas HAPs), and particulate matter (as a surrogate for non-mercury HAP metals).

- Whether the geographical area surrounding the project is designated as "in attainment" with National Ambient Air Quality Standards (NAAQS)
- The rate of fuel (heat) input to the boiler
- The annual mass flow rate of air emissions relative to relevant thresholds for each regulated constituent (e.g., NO_x, CO, HCl, etc.)

In addition, recent rulings by US EPA and subsequent court rulings impact permitting requirements for biomass facilities. In 2011, US EPA implemented a regulatory framework for the regulation of greenhouse gases (GHGs, e.g., carbon dioxide [CO_2], methane [CH_4] and nitrous oxide [N_2O]) for facilities that emit more than 100,000 tons per year of CO_2, or an equivalent amount of total GHGs. This framework is known as the GHG Tailoring Rule. Biomass facilities were initially exempted from the requirements of the Tailoring Rule for 3 years (pending further review by US EPA), but in July 2013, the US Court of Appeals ruled that the exemption for biomass was not justified.[41] Biomass plants greater than 8 to 10 MW in size would likely exceed the 100,000 ton per year threshold. For most biomass plants that exceed this threshold, compliance measures associated with the Tailoring Rule would be similar to those required if the facility was classified as a major source for criteria pollutants.

For the purposes of this study and considering the present regulations (as they apply to biomass facilities), it is assumed that a new (i.e., greenfield), wood-fired 35 MW biomass facility located in the Alliant Energy service territory would need to comply with the requirements of the Tailoring Rule, which would include completion of detailed air emissions analyses and review by state regulatory agencies. To comply with these requirements, it is assumed that the facility would employ the following air AQC systems:

- Either Selective Catalytic Reduction (SCR) or Selective Non-Catalytic Reduction (SNCR) systems for control of NOx.
- Sorbent injection for control of SO2 and acid gases (e.g., HCl).
- Powder activated carbon (PAC) injection for control of mercury.
- Fabric filter for control of PM.

Considering these assumptions, representative permitted emission limits for a 35 MW wood-fired biomass project are listed in Table 8-7.

[41] Environment & Energy Publishing Greenwire. "Court rejects EPA rule that deferred carbon standards for biomass industry." July 12, 2013. Accessed online at: http://www.eenews.net/greenwire/2013/07/12/stories/1059984329.

Table 8-7 Representative Emission Rates and Permit Limits for 35 MW (Wood-Fired) Biomass Project

CONSTITUENT	EMISSION RATE	
	STOKER BOILER	FLUID BED BOILER
CO_2[(1)], lb/MBtu	227	227
NO_x, lb/MBtu	0.08	0.08
SO_2[(2)], lb/MBtu	0.024	0.024
CO[(3)], lb/MBtu	0.22	0.08
PM, lb/MBtu	0.03	0.0098
HCl, lb/MBtu	0.022	0.022
Hg, lb/MBtu	0.0000008	0.0000008

Assumptions:

- Based on recent court rulings, it is anticipated that biomass facilities would not be exempt from GHG regulations (i.e., the Tailoring Rule). Therefore, because a 35 MW biomass facility would emit greater than 100,000 tons per year of CO_2, it is anticipated that the facility would be subject to the requirements of the Tailoring Rule, including detailed air emissions analyes and more stringent emission limits.
- It is assumed that a 35 MW biomass would be classified as a major source for HAPs (i.e., relative to IB MACT requirements).
- To comply with air quality regulations, it is assumed that a 35 MW biomass facility would employ the following air quality control systems:
    - Either Selective Catalytic Reduction (SCR) or Selective Non-Catalytic Reduction (SNCR) systems for control of NO_x.
    - Sorbent injection for control of SO_2 and acid gases (e.g., HCl).
    - Powder activated carbon (PAC) injection for control of mercury.
    - Fabric filter for control of particulate matter.
- Facility would operate with a capacity factor of 85% but would be permitted to operate a total of 8,760 hours per year.

Notes:

1. While carbon dioxide emissions are governed by present air quality regulations, it is assumed that carbon capture systems would not be considered cost-effective technology for smaller scale (i.e., less than 100 MW) power generation facilities. Emission rate for carbon dioxide is based on the Potential to Emit (PTE) and assumes the typical carbon content of solid biomass fuels.
2. Sulfur dioxide emission rate is based on PTE and assumes a typical sulfur content for woody biomass (i.e., approximately 0.02 wt%, dry basis). Based on this sulfur content, the facility would emit SO_2 at a maximum rate of 0.047 lb/MBtu. Assuming a 50% removal efficiency (via sorbent injection), the permitted limit is assumed to be 0.024 lb/MBtu.
3. Within IB MACT regulations, carbon monoxide permitted emission limits are presented on a "ppm" basis (at 3% O_2 in the exhaust stream) as measured by Continous Emission Monitoring System (CEMS). These limits are 620 ppm (at 3% O_2) for stoker boilers and 230 ppm (at 3% O_2) for fluidized bed boilers. Values shown on a lb/MBtu basis are based on estimated mass flow rates for similar biomass combustion systems.

While the values provided in Table 8-7 are considered to be representative for a greenfield facility firing woody biomass, a detailed permitting analysis (considering the preliminary design of the facility and the characteristics of the anticipated biomass fuel supply) and consultation with the appropriate regulatory agencies would be required to determine the permit limits for any specific biomass project built within the Alliant Energy service territory.

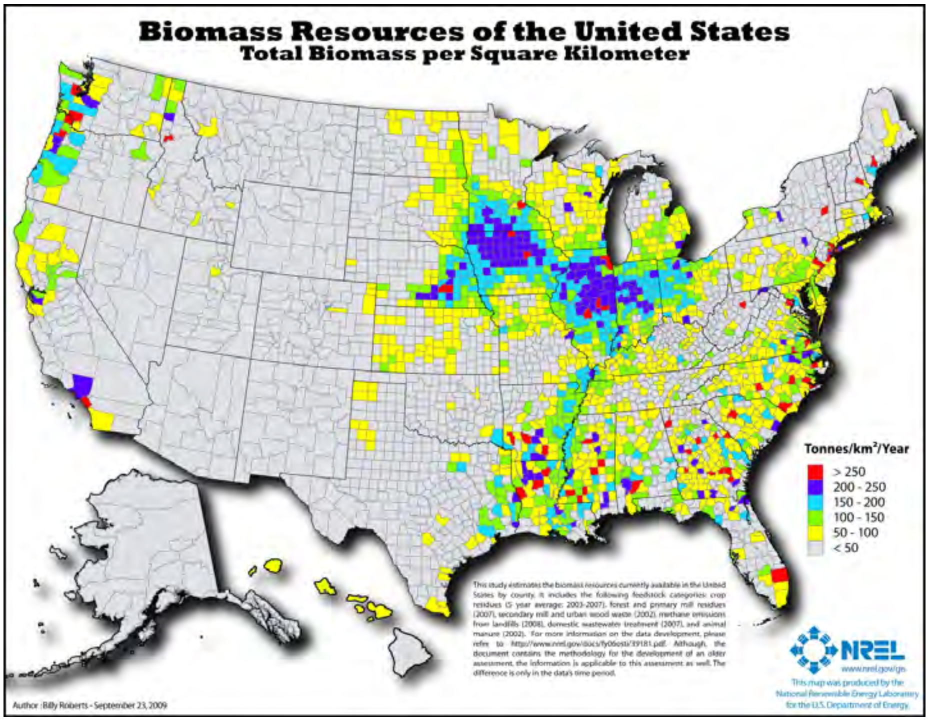
In addition to complying with air permitting requirements, biomass power projects must maintain a delicate balance to ensure long-term sustainability with minimal environmental impact. Several states impose specific criteria on biomass power projects for them to be classified as renewable energy sources. A key concern is sustainability of the feedstock. Most biomass projects target utilization of biomass waste material for energy production, saving valuable landfill space. Targeting certain wastes for power production (such as forest thinnings to reduce the threat of fire) can also address other emerging problems. Projects relying on forestry or agricultural products must be careful to ensure that fuel harvesting and collection practices are sustainable and provide a net benefit to the environment.

8.3.1.6 Development Potential

There is reasonable potential for power production from biomass combustion in the Alliant Energy territory. Currently, there is more than 700 MW of biomass generation capacity, primarily from the wood products industry, in Alliant Energy's service territory.[42] However, these plants are most often designed to meet the power demands of wood product company, without excess generation to export to the grid. It is unlikely that these plants provide an opportunity for additional power generation from biomass. While these plants would compete for fuel with any new biomass power plant, the combined biomass consumption of the currently operating plants is on the order of 4.5 million dry tons per year or significantly less than the feedstock available as noted below. The existence of currently operating plants indicates a more mature market for biomass as a fuel source.

There is no shortage of available feedstock in the Alliant Energy service territory. Figure 8-10 shows the relative concentration of biomass resources including agricultural residues, wood residues, landfill and wastewater gas (not applicable to co-firing or direct fired biomass), and dedicated energy crops. Iowa, Minnesota, and Wisconsin combined produce an estimated 48 million dry tons of combustible biomass per year. This includes urban and mill residues, forest residues, and agricultural residues. The large majority of the available biomass is in the form of agricultural residues, specifically corn stover and wheat straw. Current soil conservation practices restrict the total collectable quantity. Iowa produces more than 23 million dry tons of agricultural residues per year, with Minnesota and Wisconsin producing 11.9 million and 5.2 million dry tons per year, respectively. The primary concerns in utilizing this biomass include harvest and transportation costs and the difficulty of storing biomass fuel year round. Proper siting would allow one or more biomass power plants to have access to adequate fuel supply.

[42] Ventyx Velocity Suite, queried in February 2010.



(Source: NREL)

Figure 8-10 US Biomass Resources per Square Kilometer / yr

There are very good opportunities for the growth of energy crops throughout the Alliant Energy territory. Switchgrass has received attention as a potential energy crop, particularly in Iowa where it is a native grass and grows well on land that is otherwise ill-suited for crop production. Minnesota and Wisconsin also have very good potential for the production of a variety of energy crops. The US DOE estimates the combined energy crop potential of these two states to be more than 10 million dry tons per year.

8.3.2 Biomass Co-firing

An economical method of burning biomass is to co-fire it with coal in existing plants. Co-fired projects are usually implemented by retrofitting a biomass fuel feed system to an existing coal plant, although greenfield facilities can also be readily designed to accept a variety of fuels.

8.3.2.1 Applications

There are several methods of biomass co-firing that could be employed for a project. The most appropriate system is a function of the biomass fuel properties and the coal boiler technology. Provided they were initially designed with some fuel flexibility, stoker and fluidized bed boilers generally require minimal modifications to accept biomass. Simply mixing the fuel into the coal pile may be sufficient (refer to Figure 8-11).

Cyclone and pulverized coal (PC) boilers require a smaller fuel size than stoker and fluidized bed boilers and may require additional processing of the biomass prior to combustion. There are two basic approaches to co-firing in this case. The first is to blend the fuels and feed them together to the coal processing equipment (i.e., crushers or pulverizers). In a cyclone boiler, approximately 10 percent of the coal heat input could be replaced with biomass using this method. A PC boiler may be limited to approximately 3 percent fuel replacement due to the smaller fuel particle size requirements of PC boilers. The second approach of separate biomass processing and injection allows higher co-firing percentages (10 percent and greater) in a PC unit but costs more than processing a fuel blend.

Figure 8-11 Coal and Wood Mix

Even at these limited co-firing rates, plant owners have raised numerous concerns about the potential negative impacts of biomass co-firing on plant operations. These concerns include the following:

- Negative impact on plant capacity.
- Negative impact on boiler efficiency.
- Ash contamination affecting ability to sell coal ash.
- Increased O&M costs.
- Minimal NO_x reduction potential (usually proportional to biomass heat input).
- Boiler fouling/slagging because of the high alkali in biomass ash. This is more of a concern with fast growing biomass such as energy crops.
- Potentially negative impacts on SCR air pollution control equipment (catalyst poisoning).

These concerns have been a major obstacle to more widespread biomass co-firing adoption by utilities in the United States. However, most of these concerns can be addressed through proper system design, fuel selection, and limiting the amount of co-firing.

Coal and biomass co-firing may also be considered in the design of new power plants. Designing the plant to accept a diverse fuel mix allows the boiler to incorporate biomass fuel, ensuring high efficiency with low operations and maintenance impacts. Fluidized bed technology is often the preferred boiler technology for co-firing because of the boiler's inherent fuel flexibility. There are many fluidized bed units around the world that burn a wide variety of fuels, including biomass. One example is the 240 MW circulating fluidized boiler (CFB) in Finland, which burns a mixture of wood, peat, and lignite (refer to Figure 8-12). This unit has been proven capable of burning any fuel combination between 100 percent biomass and 100 percent coal. Kvaerner Pulping supplied this unit, which was commissioned in 2001. (The Kvaerner technology is now marketed by Metso Power.)

(Source: Kvaerner)

Figure 8-12 Alholmens Kraft Multi-Fuel CFB

8.3.2.2 Resource Availability

For viability, the coal plant should be within 100 miles of a suitable biomass resource. The United States has the largest installed biomass power capacity in the world. Biomass power plants in the United States provide 7,000 MW of power to the national power grid. According to the Energy Information Administration, coal power generation accounted for more than 2 trillion kWh in 2008, which comprised about 54 percent of the total generation in the United States. Conversion of as little as 3 percent of this generation to biomass derived co-firing would increase electricity production from biomass by nearly 150 percent.

8.3.2.3 Cost and Performance Characteristics

Table 8-8 provides typical characteristics for a co-fired plant using biomass as a fuel source. The characteristics are based on co-firing 30 MW of biomass via separate injection in a 400 MW PC power project. Except for fuel, the characteristics are provided on an incremental basis (changes that would be expected compared to the coal plant). The primary capital cost for the project would be related to the biomass material handling system. As with direct-fired biomass, biomass fuel cost is assumed to range from $2.00/MBtu for urban wood residues to $3.50/MBtu for forestry residues. To calculate the incremental fuel cost, if coal is assumed at a base cost of $2.00/MBtu, the incremental biomass cost would then ($0/MBtu) to $1.50/MBtu.

Table 8-8 Co-fired Biomass Technology Characteristics

	30 MW CO-FIRED BIOMASS
Performance	
Typical Duty Cycle	Baseload (typically, depends on host site)
Net Plant Capacity, MW	30
Net Plant Heat Rate, Btu/kWh	Increase 0.5 to 1.5 percent
CF, percent	Unchanged
Economics, Incremental Costs in 2013$	
Overnight EPC Cost, $/kW$_{biomass}$ (1)	1,000 to 1,500
Owner's Cost Allowance, percentage of EPC Cost	10
Total Project Cost, $/kW (3)	1,100 to 1,650
Fixed O&M, $/kW-yr	15 to 30
Variable O&M, $/MWh	Included in Fixed O&M
Fuel Cost, $/MBtu(3)	2.00 to 3.50
Applicable Incentives	None
Technology Status	
Commercial Status	Established, not fully commercial
Project Duration, NTP to COD, months	18

Notes:
1. Overnight EPC cost assumes co-firing via separate injection of biomass and coal.
2. O&M cost estimate assumes (1) co-firing via separate injection of biomass and coal and (2) use of automated stockout and reclaim systems.
3. Fuel cost for biomass does not account for avoided coal purchases.

8.3.2.4 Environmental Impacts

As with direct-fired biomass plants, the biomass fuel supply must be collected in a sustainable manner. Assuming this is the case, co-firing biomass in a coal plant generally has overall positive environmental effects. The clean biomass fuel typically reduces emissions of SO_2,

CO_2, NO_x, and heavy metals, such as mercury. Furthermore, compared to other renewable resources, biomass co-firing directly offsets fossil fuel use (unlike intermittent technologies such as wind which could offset gas, coal, nuclear, or even other renewables such as hydroelectric). It may also provide an alternative to landfilling wastes, particularly wood wastes.

8.3.2.5 Development Potential

There is potential for power production from co-fired biomass combustion in the region. Alliant Energy has been involved with test projects to co-fire switchgrass and coal at the 650 MW Ottumwa Generating Station. Coal plants supply the majority of the power delivered in the Alliant Energy region. Iowa, Minnesota, and Wisconsin have a combined coal fired capacity of more than 25,000 MW. Without major plant modifications (i.e., biomass is commingled with coal on the reclaim belt and biomass and coal are co-milled in existing pulverizers), up to about 3 percent of the boiler heat input could technically be replaced with biomass. Even this relatively small co-firing percentage would yield a significant increase in biomass power production.

8.3.3 Biomass Integrated Gasification Combined Cycle

BIGCC is an emerging technology that converts solid biomass into a gaseous fuel which can then be combusted or otherwise utilized. There are numerous uses for the gas and many different gasifier technologies. IGCC is a developing application that combines a gasifier with a conventional combined cycle power plant (combustion turbine followed by a steam cycle). All of the demonstration and commercial scale IGCC plants constructed worldwide have been fossil fueled. There are no IGCC plants currently operating with biomass as a primary fuel.

8.3.3.1 Operating Principles

Biomass gasification is a process to convert solid biomass into a gaseous fuel. This is accomplished by heating the biomass in an environment that is low in oxygen. Gasification is a promising process for biomass conversion. By converting solid fuel to a combustible gas, gasification enables the use of more advanced and efficient energy conversion processes, such as gas turbines and fuel cells, to produce power and chemical synthesis to produce ethanol and other value added products. There are a variety of gasification technologies including updraft, downdraft, fixed grate, entrained flow, fluidized bed, and molten metal baths. The technology choice depends primarily on the fuel characteristics and the desired capacity of the plant.

Most biomass gasification systems are air blown. The primary product of air-blown gasification is a low heating value fuel gas, typically 15 to 20 percent (150 to 200 Btu/ft^3) of the heating value of natural gas (1,000 Btu/ft^3). Using oxygen, steam, or indirect heating results in a higher quality gas, although at higher costs.

8.3.3.2 Applications

The primary advantage of gasification over direct combustion is the versatility of the gasification product. Gasification expands the use of solid fuel to include practically all the uses of natural gas and petroleum, including close coupled boilers, combustion engines and turbines, fuel cells, and chemical synthesis. The various fuel gas conversion options are illustrated on Figure 8-13.

In the mid- to late-1990s, development of BIGCC processes was the principal focus areas for biomass gasification technology developers. In an IGCC plant, the syngas exiting the gasifier is cleaned and combusted in a combustion turbine, thereby generating power. Waste heat from the gas turbine is used to generate steam for use in a Rankine steam cycle. Net conversion to electricity for BIGCC plants is projected to be approximately 35 percent, compared to 20 to 25 percent for direct-fired biomass plants. The potentially significant increase in efficiency makes BIGCC attractive; however, problems experienced with technology demonstration have yet to be overcome.

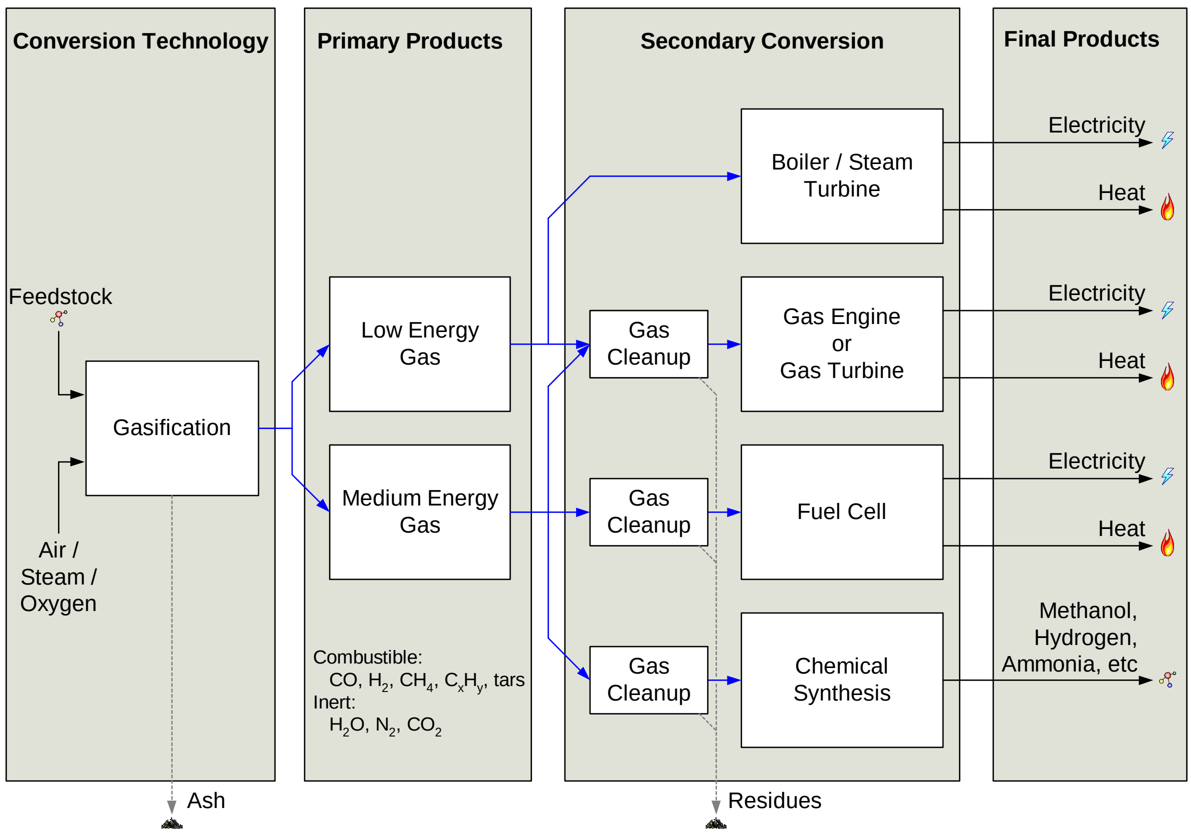


Figure 8-13 General Gasification Flow

Although there are many gasifiers installed that produce fuel gas for close coupled combustion in a boiler (essentially staged combustion), recent attempts to demonstrate more advanced processes, such as BIGCC, have not been successful. Issues have been related partially to the gasification process itself, but also to supporting ancillary equipment, such as fuel handling and gas cleanup. Regardless, there are several biomass gasification equipment suppliers, including Foster Wheeler, Energy Products of Idaho, and Primenergy, which continue to develop biomass gasification technology for other applications.

8.3.3.3 Resource Availability

A biomass gasification or BIGCC plant would have similar resource availability issues as a direct-fired biomass plant. To be economically feasible, it should be located either at the source of a fuel supply or within 50 to 75 miles of numerous suppliers. Proximity to a high quantity fuel supply is more critical to a BIGCC plant because of high capital costs. Wood, wood byproducts, agricultural residues, energy crops, and urban wood wastes are all suitable fuels for a BIGCC plant.

Like other biomass conversion technologies, a BIGCC plant would be limited in capacity by the amount of resources which could feasibly be delivered. A reasonable estimate for this limit is 30 to 75 MW, depending on location.

8.3.3.4 Cost and Performance Characteristics

Given the lack of commercial experience of the BIGCC technology, cost and performance estimates are uncertain.

8.3.3.5 Environmental Impacts

A BIGCC project would have the same long-term sustainability concerns as other biomass conversion technologies. Biomass is viewed as a carbon-neutral power generation fuel. While CO_2 is emitted during biomass conversion, a nearly equal amount of CO_2 is absorbed from the atmosphere during the biomass growth phase. Furthermore, biomass fuels contain little sulfur compared to coal and, therefore, produce less SO_2. Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals, such as mercury, cadmium, and lead. Biomass gasification technologies will require equipment to control emissions of NO_x, PM, and CO to maintain air emissions standards.

It is important to note that because a BIGCC plant is expected to have higher efficiency than a similar-sized biomass combustion-based power plant, the air emissions (on a lb/MBtu basis) are expected to be lower for a BIGCC plant than for a combustion plant.

Table 8-9Table 8-9 presents projected characteristics for a BIGCC combustion plant that utilizes urban wood waste and forest residues.

8.3.3.6 Environmental Impacts

A BIGCC project would have the same long-term sustainability concerns as other biomass conversion technologies. Biomass is viewed as a carbon-neutral power generation fuel. While CO_2 is emitted during biomass conversion, a nearly equal amount of CO_2 is absorbed from the atmosphere during the biomass growth phase. Furthermore, biomass fuels contain little sulfur compared to coal and, therefore, produce less SO_2. Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals, such as mercury, cadmium, and lead. Biomass gasification technologies will require equipment to control emissions of NO_x, PM, and CO to maintain air emissions standards.

It is important to note that because a BIGCC plant is expected to have higher efficiency than a similar-sized biomass combustion-based power plant, the air emissions (on a lb/MBtu basis) are expected to be lower for a BIGCC plant than for a combustion plant.

Table 8-9 BIGCC Technology Characteristics

	35 MW BIGCC
Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity, MW	35
Net Plant Heat Rate, Btu/kWh	10,000 to 11,500
CF, percent	75 to 85
Economics, 2013$	
Overnight EPC Cost, $/kW	6,000 to 8,000
Owner's Cost Allowance, percentage of EPC Cost	25
Total Project Cost, $/kW	7,500 to 10,000
Fixed O&M, $/kW-yr	300 to 360
Variable O&M, $/MWh	15 to 20
Fuel Cost, $/MBtu	2.00 to 3.50
Applicable Incentives	Open loop: $11/MWh PTC(1), 5 yr MACRS Closed loop: $23/MWh PTC(1), 5 yr MACRS
Technology Status	
Commercial Status	Demonstration
Installed US Capacity, MW	0
Project Duration, NTP to COD, months	42

Notes:

1. The duration of the eligibility period for the PTC is 10 years after the date the facility is placed in service.

8.4 BIOGAS

Biogas technology refers to the process of generating electricity with gas captured from the anaerobic digestion (AD) of manure or biosolids or from naturally occurring LFG. The following subsections describe the formation of these biogases and their ability to produce renewable energy.

8.4.1 Anaerobic Digestion

Anerobic digestion (AD) is defined as the decomposition of biological wastes by microorganisms, usually under wet conditions, to produce a gas comprising mostly methane and CO_2. This process occurs in the absence of air (specifically oxygen). Anaerobic digesters have been used extensively for municipal and agricultural waste treatment for many years. Traditionally, the primary driver for AD projects has been waste reduction and stabilization rather than energy generation. Increasingly stringent agricultural manure and sewage treatment management regulations, interests in diverting organic materials (such as food wastes) from landfills, and greater value for renewable energy has heightened interest in the potential for AD technologies. A schematic of a single vessel anaerobic digester is provided on Figure 8-14. While this schematic shows feedstock from a wastewater plant, a similar arrangement would be suitable for dairy manure, food waste, or other low solids organic material.

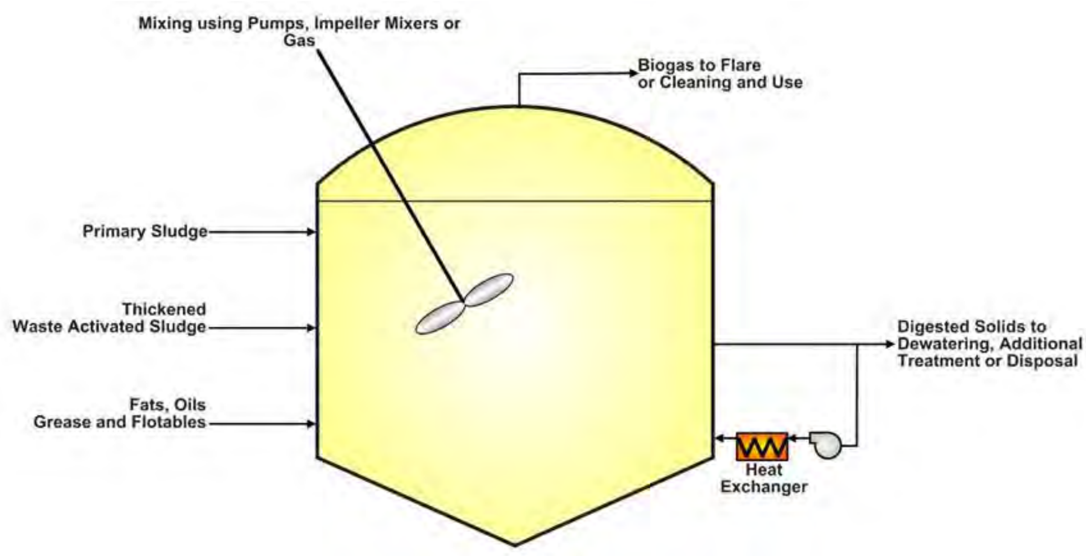


Figure 8-14 Schematic of a Single-Vessel Anaerobic Digester

8.4.1.1 Applications

According to the United States Environmental Protection Agency (US EPA) and the Combined Heat and Power (CHP) Partnership, an estimated 437 MW of capacity is produced through the AD of organic material at 133 facilities across the United States,[43] largely wastewater treatment plants. In addition to the facilities cataloged by the CHP Partnership, the EPA AgStar program tracks farm-based digestion projects across the United States. Based on 2011 data, there are currently about 176 farm-based digesters with a combined capacity of more than 50 MW.

While codigestion of municipal biosolids with other organic material such as food wastes and fats, oils, and greases (FOG) is common, it is rare in the US to have stand-alone food waste digestion largely due to cost. Food waste and agricultural digestion is much more common in Europe and locations where the disposal costs and incentives are higher for organic feedstocks.

Biogas produced by AD facilities can be used in a variety of ways, including heating/steam generation, cogeneration of electricity and heat (i.e., CHP) production), gas pipeline injection, and vehicle fuel usage. Most commonly, biogas generated at digestion facilities is utilized onsite for process heat or CHP applications. Technologies that can be used to convert biogas to electricity include reciprocating engines, gas turbines, fuel cells, and microturbines. The technology selection depends on the size, level of CHP desired, cost, and level of emissions control.

Municipal Biosolids

Biosolids is the term given to processed sludge removed from wastewater treatment. Biosolids are rich in organic materials and can be used to produce energy either through combustion or AD. However, the high moisture and ash contents of biosolids create challenges when the resource is combusted for energy. Even dewatered biosolids typically have a moisture content of approximately 70 percent, and ash contents are typically greater than 20 percent (of the dry biosolids). While combustion may become more attractive if waste heat or natural evaporation can be used to dry biosolids, energy production from biosolids is typically achieved via anaerobic digestion and subsequent utilization of the derived biogas.

AD is commonly used in municipal wastewater treatment as a first-stage treatment process for sewage sludge. However, historically, efficient utilization of the biogas generated from municipal AD facilities has been a secondary consideration. As interest in sustainability increases, more water utilities are considering biosolids as a potential energy resource and are evaluating the optimal way to use their biogas.

[43] US Environmental Protection Agency, Combined Heat and Power Partnership, "Opportunities at Wastewater Treatment Facilities," October 2011.

Food Wastes

Primary types of AD gas producing food wastes are fats, oils and greases (FOG) and vegetable or dairy waste. Food waste with low moisture content, fats and proteins (including meats) generate more biogas than high moisture content or high carbohydrate foods.[44]

Gathering food waste feedstock can often involve a municipality with an aggressive food waste separation and collection target and a willingness to participate in public/private partnerships. Traditional waste haulers can be effective participants such as Recology in San Francisco. A planned Columbia Biogas plant[45] may benefit from a food waste stream identified and organized by the Portland Metro Regional Government.[46] Food retailer Kroger hosts a 50,000 ton per year anaerobic digestion food waste to biogas facility operated by FEED Resource Recovery at a distribution center in Compton, CA for its Ralph's/Food 4 Less stores.[47]

Animal Manures

Animal manures from concentrated animal feeding operations are another opportunity for biogas creation via anaerobic digesters. They typically rely on relatively simple technologies, such as covered lagoon or horizontal plug flow reactors. The animal type, population, and manure collection/management system are the largest factors in determining the potential and feasibility of a farm-based project. Other important factors that influence the biogas producing potential are the technology type and process parameters (such as temperature and residence time). In recent years, there has been a trend toward larger, more advanced, complete mix digesters. A photo of a dairy manure digester is shown on Figure 8-15.

As discussed previously, digestion projects are often not motivated solely by energy issues. Waste reduction and stabilization are generally the primary drivers. Larger projects benefit from economies of scale and hold the most potential to be economically viable with regards to energy production.

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[44] Biogas Frequently Asked Questions, University of Florida, Dr. Ann C. Wilkie, updated and accessed August 2013.
[45] Columbia Biogas web site Facility page, http://www.columbiabiogas.com/ourFacility/index.html, accessed August 2013.
[46] *"Portland Metropolitain Industrial Food Waste Study Report"*, Martin Lott, April 19, 2010.
[47] *"Kroger Opens Food Waste to Biogas Anaerobic Digestion Plant"*, Waste Management World, Ben Messenger, May 17, 2013.

Figure 8-15 Diary Manure Digester Facility

8.4.1.2 Resource Availability

The EPA AgStar program identifies three existing projects in Iowa, six in Minnesota, and 26 in Wisconsin. The total generation of these projects was 185,292 MWh/yr, and they range in size from 37 kW up to 1.2 MW.

For farm-based AD projects, the resource is readily accessible, and only minor modifications to existing manure management techniques are required to produce biogas suitable for power generation. In some cases, economies of scale may be realized by transporting manure from multiple farms to a central digestion facility. For central plant digestion of manure from many farms, the availability of a large number of livestock operations within a close proximity is necessary to provide a sufficient flow of manure to the facility. However, the larger size of regional facilities does not necessarily guarantee better economics because of high manure transportation costs.

For the anaerobic digestion of municipal sewage wastes, the resource is readily available at wastewater treatment plants. Most large wastewater plants have already implemented some sort of AD process to manage their biosolids. Opportunities exist at facilities that are flaring a portion of their biogas, that have excess digester capacity, or that could upgrade their existing CHP system.

For the anaerobic digestion of food wastes, the significant food waste suppliers tend to be large food processing companies and grocery stores which can provide high volumes of reasonably consistent material. Commercial and residential food wastes may also be collected, but the waste from commercial and residential sources tends to be more expensive due to the number of suppliers and the additional efforts required to sort the food wastes.

8.4.1.3 Cost and Performance Characteristics

Table 8-10 provides typical characteristics of farm-scale dairy manure AD systems utilizing reciprocating engine technology. However, costs for AD systems are very site specific. Variations in capital costs are due primarily to the feedstock (substrate) being digested and the technology selected (e.g., lagoon, plug flow, or complete mix). The range in CFs is a result of the complexity of the system and the availability of the feedstock.

Table 8-10 Anaerobic Digestion (Food Waste) Technology Characteristics

	1 MW DIGESTER GAS-FIRED RECIPROCATING ENGINE
Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity, MW	1.0
Net Plant Heat Rate, Btu/kWh	10,000
CF, percent	70 to 90
Economics, 2013$	
Total Project Cost, $/kW	8,000 to 11,000
Owner's Cost Allowance, percentage of EPC Cost	15
Total Project Cost, $/kW	9,200 to 12,700
Fixed O&M, $/kW-yr	400 to 600
Variable O&M, $/MWh	Included in Fixed O&M
Fuel Cost, $/MBtu(1)	0.00
Applicable Incentives	$11/MWh PTC(2),(3)
Technology Status	
Commercial Status	Commercial
Installed Worldwide Capacity, MW	2,470(4)
Project Duration, NTP to COD, months	12

Notes:

1. It is assumed that food waste would be provided without cost to the facility. In many cases, the digestion facility may receive a tipping fee to accept the waste.
2. PTC depends on waste material used.
3. The duration of the eligibility period for the PTC is 10 years after the date the facility is placed in service.
4. Estimated. Agricultural AD for power generation is not well tabulated or separated from MSW, Wastewater and other biogas production. Because of an aggressive Feed-In Tariff incentive, Germany has added 1,470MW of agricultural AD since 2009 per the German Biogas Association, IEA Bioenergy task 37, Country Report-Germany, April 2013.

8.4.1.4 Environmental Impacts

ADs have several positive environmental impacts. First, they provide a dependable waste stabilization process that significantly reduces pathogens in the waste stream. Odor problems are also eliminated. Methane emissions, which are a significant contributor to greenhouse gas emissions, are reduced in relation to atmospheric decomposition of manure. In addition, biogas digesters can be incorporated as an important part of farm nutrient management planning, to prevent nutrient overloading in the soil that may result from manure spreading. Finally, biogas used for power production displaces the use of fossil fuels.

For digester gas-fired reciprocating engines, typical emission rates are summarized in Table 8-11.

Table 8-11 Emissions from Digester Gas-Fired Reciprocating Engines

CONSTITUENT	EMISSIONS FACTOR (BASED ON FUEL INPUT)
CO_2(1), lb/MBtu	120
NO_x(2), lb/MBtu	0.2
SO_2(3), lb/MBtu	0.028
CO(3), lb/MBtu	0.6
PM, lb/MBtu	0.01
Hg, lb/MBtu	0

Notes:

1. Emission rate for CO2 is based on the PTE and assumes the typical carbon content of gaseous fuels.
2. Emission rates for NOx, CO, and PM are based on assumed rates of 0.6 g/bhp-hr, 1.6 g/bhp-hr, and 0.03 g/bhp-hr, respectively..
3. Emission rate for SO_2 assumes (1) that sulfur content (as H_2S) of the digester gas/LFG is controlled to 100 ppm (on a volumetric basis) prior to combustion, and (2) that all sulfur is converted to SO_2.
4. Emission rate for Hg assumes negligible content of this constituent in digester gas.

8.4.1.5 Development Potential

The use of biogas from anaerobic digesters in Alliant Energy's territory could provide electric generation to be used onsite (i.e., the host water treatment facility or farm) and as well as small exports of power back to the grid.

Agricultural

The Alliant Energy service region covers vast areas of farmland, with a large number of livestock and some very large individual operations. In all three states within the region, there are several installations already in place and there is some potential for additional gas collection and utilization.

The feasibility of a digestion installation would depend highly on the amount of resources available, which is proportional to the number and type of livestock. The primary livestock operations in the region are hog and dairy farms. Generally for economic feasibility, a minimum size of 300 dairy cows or 2,000 swine is necessary. In Wisconsin, dairy farms comprise more than 20 million head, with many operations having more than 500 head. Such farms could provide power production. According to the United States Department of Agriculture (USDA), fewer than 2 percent of Wisconsin dairy farms are over 500 head.[48] While actual gas production varies significantly among installations, a reasonable range for production from a 500 head dairy cattle farm would be between 50 and 100 kW. Plans for a 1.4MW manure digester at the 8,000 cow Rosendale Dairy near Pickett, WI were announced in July of 2013. The project involves Alliant Energy, vendors, and the University of Wisconsin – Oshkosh (UWO).[49]

Although there are many dairy farms in Iowa, the primary livestock in the state is swine. Minnesota also has significant swine farm operations, with an increase in numbers over the last 10 years. Together, Iowa and Minnesota have more than 25 million swine, with the majority on farms with greater than 1,000 head. Iowa Department of Natural Resource data indicate approximately 179 swine-finishing operations of more than 5,000 head, which could theoretically provide at least 50 kW at each location. For very large swine operations (20,000 head), power production could approach 300 kW.

Based on the existing animal populations and "per animal" estimates of generation potential stated above, estimates of generation potential from anaerobic digestion within the Alliant Energy service territory are summarized in Table 8-12.

Table 8-12 Estimate of Anaerobic Digestion Potential within Alliant Energy Service Territory

STATE	ANIMAL	NUMBER OF ANIMALS ON FARMS OF AD SIZE(1)	KW CAPACITY PER MINIMUM NO. OF ANIMALS	MINIMUM NO. OF ANIMALS	ESTIMATE OF MW CAPACITY
WI	Dairy	257,300	75	500	38.6
WI	Swine	183,700	50	2000	4.6
IA	Dairy	64,500	75	500	9.7
IA	Swine	16,220,000	50	2000	405.6

Notes:
1. Assumes (>500 dairy and >2,000 hogs)
Source: USDA NASS Census of Agriculture

[48] "Wisconsin Dairy Operations by Size Group, 2003-2007, "*United States Department of Agriculture,*" http://www.nass.usda.gov/Statistics_by_State/Wisconsin/Publications/Dairy/dyopbysizegroup.pdf.

[49] "*States largest dairy farm kicks off waste-to-energy project*", JSOnline/Milwaukee Journal-Sentinel, July 9, 2013, http://www.jsonline.com/business/states-largest-dairy-farm-kicks-off-waste-to-energy-project-b9950892z1-214851711.html

Municipal Wastewater Treatment Plants

As an approximation, Black & Veatch estimates the generation potential of wastewater treatment plants (WWTP) is roughly 0.3 MW per every 10 MGD of water treated at the WWTP. The Milwaukee Metropolitan Sewerage District (MMSD) Jones Island WWTP treats approximately 190 MGD of wastewater. Jones Island produces Milorganite fertilizer rather than digesting biosolids to generate biogas and produce electricity. However, a facility similar in size to Jones Island would provide the potential to generate approximately 50 to 60 MW of biogas-derived generation.

Food Waste

Wisconsin and Iowa are states with significant activity in food production, processing and the resulting waste that is potentially suitable for anaerobic digestion. GreenWhey Energy plans a 3.2MW anaerobic food digester near Turtle Lake, WI using cheese and dairy feedstock from multiple processors.[50] For metropolitan area food waste digestion, exclusive of a large, high quality food processor, a high-level approximation of generation potential using about one-half FOG[51] and one-half food waste[52] for the cities of Milwaukee and Madison, WI would be 9 MW and 3 MW respectively. The City of Madison is conducting a household organics collection pilot program. That city budgeted funds in 2013 to design an organics digester potentially to be located at the Rodefeld Landfill in Dane County where it could utilize existing power generation equipment.[53] UWO operates a BioFerm food and organic waste digester using a dry fermentation process that provides about 15 percent of UWO's electrical needs with a capacity of approximately 300 kW.[54]

8.4.2 Landfill Gas

Landfill gas (LFG) is produced by the decomposition of the organic portion of landfilled waste. LFG typically has a methane content of between 45 and 55 percent and is considered an environmental issue. Methane is a potent greenhouse gas, 25 times more harmful than CO_2. In many landfills, a collection system has been installed, and the LFG is flared rather than released into the atmosphere. By adding power generation equipment (i.e., reciprocating engines, small gas turbines, or other devices) to the collection system, LFG can be used to generate electricity. LFG energy recovery is currently regarded as one of the more mature and successful WTE technologies.

[50] *"3.2MW Anaerobic Digestion Food Waste to Biogas Plant for Wisconsin"*, Waste Management World, Ben Messenger, February 22, 2013.

[51] Wiltsee, George (for NREL), "Waste Grease Resources in 30 Metropolitan Areas", 1999. Presented at *Bioenergy 98: Expanding Bioenergy Partnerships*.

[52] Matteson, G., and Jenkins, B. (UC Davis), "Food and Processing Residues in California: Resource Assessment and Potential for Power Generation", Bioresource Technology 98 (2007) 3098–3105, January 2007.

[53] "*Madison's Household Organics Program-What's Next"*, City of Madison web site, http://www.cityofmadison.com/streets/compost/organics.cfm, accessed August 2013.

[54] "*The University of Wisconsin–Oshkosh Biodigester*", BioFerm – Viessman Group, http://www.biofermenergy.com/references/university-of-wisconsin-oshkosh-biodigester/, accessed August 2013.

As of 2012, there are 590 operational LFG projects within the United States,[55] and these projects provide more than 1,470 MW of generation capacity.[56]

8.4.2.1 Applications

LFG can be used to generate electricity, for process heat, or may be upgraded for pipeline sales. Power production from an LFG facility is typically less than 10 MW. There are several types of commercial power generation technologies that can be easily modified to burn LFG. Internal combustion engines are the most common generating technology choice. About 75 percent of landfills that generate electricity use internal combustion engines.[57] Depending on the the scale of the gas collection facility, it may be feasible to generate power via a combustion turbine or a boiler coupled with a steam turbine. Testing with microturbines and fuel cells is also underway, although these technologies do not appear to be economically competitive for current applications.

8.4.2.2 Resource Availability

Gas production in a landfill is primarily dependent upon the depth and age of the waste in place and amount of precipitation received by the landfill. In general, LFG recovery may be economically feasible at sites that have more than 1 million tons of waste in place, more than 30 acres available for gas recovery, a waste depth more than 40 feet, and at least 25 inches of annual precipitation.

The life of an LFG resource is limited. After waste deliveries to a landfill cease and the landfill is capped, LFG production will decline. This decline typically follows a first order decay. Project lifetime for a typical LFG project is approximately 15 years, although greater lifetimes may be achievable for large landfills or landfills with multiple waste cells with staged closing dates.

8.4.2.3 Cost and Performance Characteristics

The economics of installing an LFG energy facility depend heavily on the characteristics of the candidate landfill. The payback period of an LFG energy facility at a landfill that has an existing gas collection system can be as short as 2 to 5 years, especially if environmental credits are available. However, the cost of installing a new gas collection system can prohibit the installation of an LFG facility. Table 8-13 presents cost and performance estimates for typical LFG projects using reciprocating engines. For these estimates, it is assumed that the landfill has an existing collection system and LFG gas cleaning requirements are minimal. It is noted that LFG at certain landfills contains significant quantities of siloxanes and acid gases, which can causing fouling and/or corrosion of engine components. The degree and complexity of the gas cleanup required depends on the composition of the gas drawn from the landfill.

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[55] EPA Landfill Methane Outreach Program, http://www.epa.gov/lmop/proj/index.htm.

[56] US DOE Energy Information Administration, "Trends in Renewable Energy Consumption and Electricity," released December 11, 2012. Available online at: http://www.eia.gov/renewable/annual/trends/.

[57] EPA Landfill Methane Outreach Program, http://www.epa.gov/lmop/proj/index.htm.

Table 8-13 LFG Technology Characteristics for 3 MW Reciprocating Engine

	3 MW LFG-FIRED RECIPROCATING ENGINE
Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity, MW	3
Net Plant Heat Rate, Btu/kWh	12,500
CF, percent	85 to 90
Economics, 2013$	
Overnight EPC Cost, $/kW(1)	2,000 to 3,000
Owner's Cost Allowance, percentage of EPC Cost	20
Total Project Cost, $/kW	2,400 to 3,600
Fixed O&M, $/kW-yr	65 to 75
Variable O&M, $/MWh	15 to 20
Fuel Cost, $/MBtu(2)	1.00 to 2.00
Applicable Incentives	$11/MWh PTC(3), MACRS
Technology Status	
Commercial Status	Commercial
Installed US Capacity, MW	1,400
Project Duration, NTP to COD, months	15

Notes:
1. Capital cost estimate assumes that a collection system is already in place at landfill.
2. Fuel cost is variable. The low end of this range is unlikely unless an existing gas purchase contract is in place.
3. The duration of the eligibility period for the PTC is 10 years after the date the facility is placed in service.

8.4.2.4 Environmental Impacts

LFG combustion releases pollutants similar to those released by many other fuels, but the combustion of LFG is generally perceived as environmentally beneficial. If not combusted, the methane in LFG is released to the atmosphere as a greenhouse gas. As a greenhouse gas, methane is 25 times more harmful than CO_2. Collecting the gas and converting the methane to CO_2 through combustion greatly reduces the potency of LFG as a source of greenhouse gas emissions.

For LFG-fired reciprocating engines, typical emission rates are summarized in Table 8-14.

Table 8-14 Emissions from LFG-Fired Reciprocating Engines

CONSTITUENT	EMISSIONS FACTOR (BASED ON FUEL INPUT)
CO_2(1), lb/MBtu	120
NO_x(2), lb/MBtu	0.2
SO_2(3), lb/MBtu	0.028
CO(3), lb/MBtu	0.6
PM, lb/MBtu	0.01
Hg, lb/MBtu	0

Notes:

1. Emission rate for CO2 is based on the PTE and assumes the typical carbon content of gaseous fuels.
2. Emission rates for NOx, CO, and PM are based on assumed rates of 0.6 g/bhp-hr, 1.6 g/bhp-hr, and 0.03 g/bhp-hr, respectively..
3. Emission rate for SO_2 assumes (1) that sulfur content (as H_2S) of the digester gas/LFG is controlled to 100 ppm (on a volumetric basis) prior to combustion, and (2) that all sulfur is converted to SO_2.
4. Emission rate for Hg assumes negligible content of this constituent in LFG.

8.4.2.5 Development Potential

There is good potential for power generation from LFG in the Alliant Energy territory. Currently, LFG utilization provides more than 115 MW of generation capacity at landfills in Iowa, Minnesota, and Wisconsin.[58] These facilities generate power from a number of different technologies, including combustion turbines, reciprocating engines, boilers, and in the case of one very large Minnesota landfill, a combined cycle unit.

The EPA Landfill Methane Outreach Program outlines the currently developed, candidate, and potential LFG operations for each state. Based on the amount of waste currently in place, the most attractive candidates in the Alliant Energy service region may have the combined potential to generate between 10 and 20 MW, depending on the type and efficiency of the systems.

[58] EPA Landfill Methane Outreach Program, http://www.epa.gov/lmop/projects-candidates/index.html# map-area.

8.5 BIOFUELS

Biofuels are increasingly gaining acceptance for transportation and power generation purposes. The two most common biofuels today are ethanol and biodiesel. Ethanol is generally a supplement for gasoline, while biodiesel can be used as a substitute for diesel. Table 8-15 introduces some of the key characteristics of the fuels and compares them to conventional fuels. This section discusses the two fuels in further detail.

Table 8-15 Domestic Fuel Production and Price Comparison

	GASOLINE	ETHANOL	DIESEL	BIODIESEL
Domestic Production Capacity, mbpd	8,879	868	3,680	63
Energy Content, Btu/gal (HHV)	124,300	84,500	137,400	128,000
National Average Price, $/gallon (1)	$3.59	$3.30	$3.99	$4.11 (B100) $4.29 (B20)
National Average Price, $/MBtu	$28.9	$39.1	$29.0	$32.1 - $33.5

Notes:
1. Production Source: Department of Energy, *Monthly Energy Review*, May 2013.
2. Pricing Source: Clean Cities, *Alternative Fuels Price Report*, April 2013. Pricing does not include taxes, rebates, or subsidies.

8.5.1 Ethanol

Ethanol, also called ethyl-alcohol or grain alcohol, is an alcohol that can be easily produced from common agricultural feedstocks, such as corn and sugarcane.

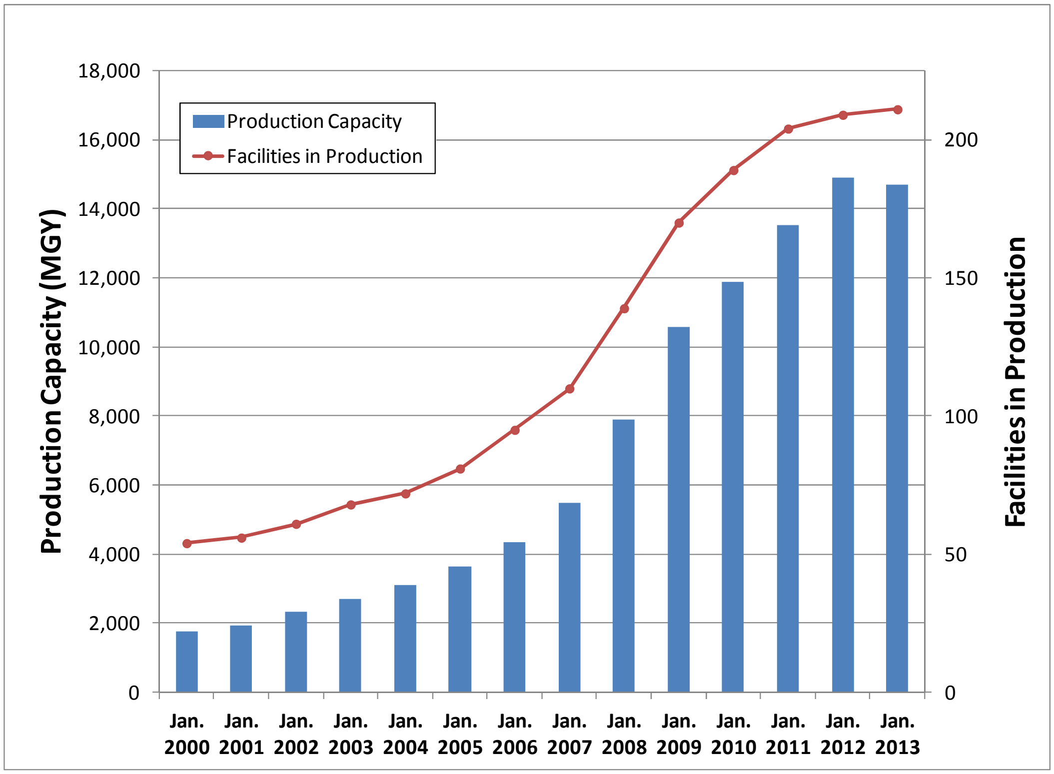
Ethanol is most commonly produced through a dry milling procedure. The biomass feedstock is milled to a fine powder and slurried with water. This causes the starch component in the biomass feedstock to break down into its simple sugars (glucose). With the addition of yeast, these simple sugars are then fermented into ethanol. After fermentation, the mash is distilled to 200 proof. To make the ethanol undrinkable, as well as to avoid any alcoholic beverage excise taxes, a denaturant (usually gasoline) is added to the ethanol.

The ethanol industry in the United States, based largely on starch-based ethanol production methods, expanded rapidly in the past decade. Production capacity increased from less than 2 billion gallons per year in 2000 to more than 13 billion gallons per year in 2012. This rapid growth, as illustrated on Figure 8-16, was spurred by increasing gasoline prices and production incentives from both federal and state governments, although it is noted that the "Volumetric Ethanol Excise Tax Credit (also known as the ethanol blender's tax credit) expired December 31, 2011.[59]

Expansion was also motivated by the enactment of the Energy Policy Act of 2005, which established the Renewable Fuel Standard (RFS). The RFS required that a percentage of the fuel supply in the United States be provided by renewable, domestic fuels. The original RFS mandated

[59] Alternative Fuels Data Center, http://www.afdc.energy.gov/laws/law/US/399

that annual renewable fuel production in the United States increase to 7.5 billion gallons by 2012. In 2007, the RFS was amended within the Energy Independence and Security Act, increasing the production levels required throughout the period from 2008 through 2022. These amended requirements are known as RFS2. Under RFS2, 36 billion gallons of biofuels (ethanol and biodiesel) are required to be blended with a cap of 15 billion gallons on corn-based ethanol and 16 billion gallons to come from cellulosic biofuels, although it appears that technological breakthroughs will be required to achieve goals for cellulosic biofuels.



(Source: Renewable Fuels Association)

Figure 8-16 Expansion of US Ethanol Industry since 2000

8.5.1.1 Applications

Since ethanol can be used in most spark ignition engines with limited or no engine modifications, ethanol may displace gasoline. Ethanol is already commonly used as a low percentage blend in automobiles (usually up to 10 percent). However, the ethanol industry is pushing to market higher percentage ethanol blends such as E15 and E85, which contains ethanol as 15 or 85 percent of the total fuel volume, respectively. (The US EPA states that all flexible-fuel vehicles and all 2001 and newer cars, light-duty trucks and medium-duty passenger vehicles (SUVs) can use E15. The US EIA estimates there are 10,000,000 E85 flexible fuel vehicles in the US.) In general, ethanol is suitable for any application in which gasoline is used. While this primarily pertains to the transportation sector, there is a variety of power production applications in which ethanol would be a possible replacement for gasoline or natural gas.

8.5.1.2 Resource Availability

While most of the ethanol produced in the United States today is derived from corn, ethanol is also produced from agricultural feedstocks that are high in simple sugars, such as sugarcane and sugar beets. Domestic sorghum-starch ethanol is another qualifying fuel under RFS2 that may be suited to regions less suitable for corn production.[60] Currently, the sugar or starch components of plants are primarily used for ethanol production. However, it is possible to utilize the more fibrous parts of biomass (i.e., cellulose, hemicellulose polymers, and lignin) to produce ethanol. While the sugar polymers in hemicellulose and cellulose are more resistant and difficult to break down using conventional dry milling processes, other production processes are being developed that allow these components to be fully utilized.

Researchers have focused their efforts on acid hydrolysis and enzymatic hydrolysis technologies that are capable of breaking down or hydrolyzing the sugar polymers in lignocellulosic biomass such as trees, grasses, and waste biomass. Processes are also under development that gasify organic feedstock (including municipal waste) and synthesize ethanol from the product gas. Multiple cellulosic ethanol plants are slated to begin commercial operation in late 2013 and 2014. These alternative processes may expand the biomass resource base and lower feedstock cost in ethanol production.

8.5.1.3 Environmental Impacts

Ethanol is a renewable fuel that has lower emissions of CO, PM, NO_x, and other ozone-forming pollutants than gasoline. The use of ethanol fuels (in place of gasoline) may reduce CO emissions by as much as 30 percent and greenhouse gas emissions by as much as 35 to 45 percent.[61]

[60] Renewable Fuel Standard (RFS): Overview and Issues, Congressional Research Service, March 14, 2013, page 29.
[61] American Coalition for Ethanol, "Environmental and Clean Air Benefits," available at http://www.ethanol.org/index.php?id=34&parentid=8#Environment. Accessed January 2010.

While the actual energy balance of ethanol was debated for several years, results of a University of California study indicate that corn ethanol yields substantially more energy than what is required to produce it.[62] It is further noted that the fossil fuels used in the process of producing ethanol are usually of domestic origin (coal and natural gas), rather than imported petroleum.[63] While these data are for today's processes for producing ethanol from corn, the predictions for ethanol production from cellulosic feedstocks were even more positive. Figure 8-17 displays the relative density of crop production in Alliant Energy's region.

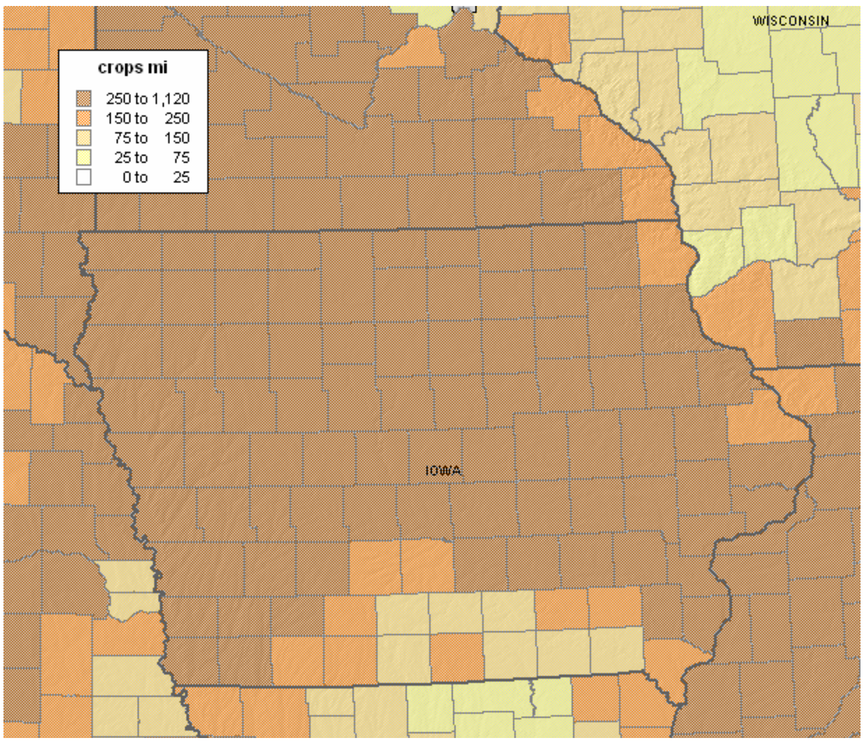


Figure 8-17 Crop Density by County (tons/mi² per year)

[62] Farrell, Alexander, et. al, "Ethanol Can Contribute to Energy and Environmental Goals," Science 311, 27 January 2006, available at http://rael.berkeley.edu/EBAMM/. Accessed 16 February 2007.
[63] Ibid, Petroleum use for ethanol production was estimated at 0.08 on a net energy basis, or 0.08 MJ of gasoline for every MJ of ethanol.

8.5.1.4 Development Potential

As a fuel, ethanol has a lower energy density than gasoline, which means that it contains less energy per unit volume than gasoline. The energy content of ethanol is 84,000 Btu/gallon, which translates into only 70 percent of the energy of gasoline. The price of ethanol is dictated by a complex interaction of the cost of the raw feedstock, the processing technology, state subsidies and national mandates, and the supply and demand of the product. Because of these factors, it is not necessarily true that a rise in gasoline prices will make ethanol comparatively cheaper. Nationally, ethanol has recently cost approximately $39/MBtu, which is about $10/MBtu more than gasoline.

Currently, the costs of ethanol production using the advanced lignocellulosic technologies are not competitive compared to conventional dry milling and wet milling processes. The high costs are attributed to the high volume acid requirements (for hydrolysis methods) and significant capital costs of equipment (for gasification/alcohol synthesis methods). Advancements in these technologies would be needed to reduce the cost of ethanol production using the lignocellulosic methods. RFS2 significantly increases the amount of "advanced biofuels" including cellulosic ethanol required to be blended through the year 2022 and caps the amount of ethanol coming from US corn production.

Domestic gasoline and diesel production far outweigh their biofuel counterparts. The market potential for ethanol is greatest in the Midwest, close to corn feedstock. According to the Energy Information Administration, as of January 2011, Iowa produced approximately 27 percent of ethanol in the United States.[64] The difference in price between the Midwest and the West Coast, which has little corn production, can be 20 cents per gallon or more. However, legislation that effectively banned methyl tertiary-butyl ether (MTBE) as a fuel additive and implemented new renewable fuel standards (e.g., RFS2) have drastically increased the market potential for ethanol.

Former USDA Chief Economist Keith Collins noted that ethanol production utilized about 6 percent of the year 2000 corn harvest. This rose to 20 percent in 2006 and was more than 23 percent in 2008. In 2011, 27.3 percent of the US corn crop was used for ethanol production.[65] Collins also stated, "Cellulosic ethanol appears to be the best biofuel for reducing crude oil imports, but making it commercially feasible on a wide scale is a formidable challenge."[66] Ethanol advocacy associations such as the Renewable Fuels Association and the American Coalition for Ethanol, as well as federal policy, are focusing more on cellulosic conversion of corn stover and many other cellulosic materials to expand the feedstock for ethanol production. At the same time, several groups are advocating for revisions or even the elimination of RFS2 expressing concerns about the industry's ability to produce adequate volume of cellulosic ethanol.

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[64] EIA State Profile – Iowa, http://www.eia.gov/state/?sid=IA, accessed June 21, 2013.

[65] National Corn Growers Association, World of Corn Report for 2011 via Ethanol Producer's Magazine, Holly Jensen, March 1, 2012, http://ethanolproducer.com/articles/8611/world-of-corn-report-breaks-down-corn-used-for-ethanol-ddgs.

[66] Statement of Keith Collins, Chief Economist, USDA, before the US Senate Committee on Agriculture, Nutrition and Forestry, January 10, 2007.

Ethanol has faced limited competition as an alternative to gasoline for vehicle fuel. Current examples include dimethyl ether (DME) and butyl alcohol (butanol or biobutanol). DME can be produced from biomass feedstock like food, animal, and agricultural wastes and from natural gas. DME is not currently in commercial-scale production in the US. However, Oberon has announced plans to use DME produced on a small scale for use in Volvo trucks operated by Safeway in the San Joaquin Valley Air Pollution Control District. Butanol has similar energy density as gasoline, can be mixed and transported with gasoline, can be blended at the refinery, can be made from cellulosic material and doesn't require engine modification at 85 percent mix with gasoline. Work is ongoing by BP, MIT and others to make biobutanol from ethanol or biomass sources, but it is not commercially available at a marketable cost.

8.5.2 Biodiesel

Biodiesel is a nontoxic, biodegradable, and renewable fuel that can be used in diesel engines with little or no modification. Biodiesel can be produced from oils and sources of free fatty acids such as animal fat, vegetable oil, and waste greases. Biodiesel is produced by removing excess hydrocarbons from these oils to create a shorter chain molecule that is chemically more comparable to diesel fuel. Sodium methoxide is added to the oil, causing the mixture to settle into two simpler constituents: glycerin and methyl ester. The methyl ester is collected, washed, and filtered to yield biodiesel. The glycerin has several commercial uses, the most common one being the manufacture of soap.

The actual facilities where biodiesel is created are relatively simple and easily scaled to meet local needs. Two kinds of biodiesel production facilities are in operation today: batch plants and continuous flow plants. Batch plants tend to be much smaller than continuous flow plants and produce discrete "runs" of biodiesel. Continuous flow plants are usually much larger, run continuously, and are capable of implementing more efficient processes than those used in batch operations. There are a limited number of large scale continuous flow biodiesel plants in operation in the United States at this time. Examples of continuous flow biodiesel plants are the Western Iowa Energy, LLC plant in Wall Lake, Iowa and the Western Dubuque Biodiesel, LLC plant in Farley, Iowa.

8.5.2.1 Applications

Biodiesel can directly displace diesel fuel in many applications. Biodiesel requires some special handling and storage procedures and is limited to use during warm or temperate seasons/climates because of its viscous nature at low temperatures. No engine modifications are required for most static compression injection (diesel) internal combustion engine applications. While there has been limited study of biodiesel's performance in gas turbine engines, there has been extensive research and testing of the fuel's performance in traditional four-stroke diesel engines. As such, biodiesel is already used in a variety of operations throughout the United States.

Biodiesel's greatest market potential lies within the transportation sector. However, diesel is generally the fuel of choice for most internal combustion engine power production. Because of this, there is potential for biodiesel to replace diesel fuel in the energy sector. A variety of stationary engine products are available for a range of power generation market applications and duty cycles, including standby and emergency power, peaking service, intermediate and baseload power, and combined heat and power. Reciprocating engines are available for power generation applications in sizes ranging from a few kW up to 20 MW.

8.5.2.2 Resource Availability

The most basic feedstock for biodiesel is vegetable oil, a long chain hydrocarbon. The oil can be derived from a variety of sources including corn, soybeans, cotton, palm, rapeseed, sunflower seeds, and restaurant waste greases. These feedstocks are generally categorized as virgin (fats and oils that have not been previously used) and recycled (fats, oils, and greases that have been previously used). While recycled feedstocks tend to have lower costs, they are limited by their availability and a variety of socioeconomic factors that may not be completely controllable. Virgin feedstocks are controlled by the available agricultural resources.

In the United States, soybean and corn oil are the two leading vegetable feedstocks for biodiesel production. These two feedstocks are readily available throughout most of the country and can be grown in the large quantities necessary to meet large scale biodiesel production demands. The pork and beef industries dictate the supply of animal grease (i.e., white grease) and tallow that is available for biodiesel production. The supply of recycled fats and oils (i.e., yellow grease) is largely determined by the demand for fried food products, lubricants, and other oil dependent industries. While biodiesel demand has been known to have moderate effects on corn and soybean production, it is unlikely that increases in the demand for biofuels will significantly affect the supply of animal fats or recycled greases.[67]

8.5.2.3 Cost Performance and Characteristics

Because the majority of biodiesel production cost is directly derived from the cost of the plant feedstock, the potential for cost reduction is less than that of ethanol. Biodiesel can be more cost-effective when produced from low cost oils (i.e., restaurant waste, frying oils, or animal fats) than when produced from commodity crops.

Integration of biodiesel into the transportation sector has been limited in the past because nearly every major diesel engine manufacturer has imposed blend limits on biodiesel for warranted operations. To be called biodiesel, the fuel must meet ASTM D6751 quality specifications. In recent years, most major engine companies have provided blend approval statements that the use of blends ranging from B5 (i.e., a diesel blend with biodiesel comprising 5 percent of the blend) to B100 (i.e., 100 percent biodiesel) will not void their parts and workmanship warranties.[68]

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[67] Agricultural Marketing Research Center, "Biodiesel as a Value-added Opportunity," available at <http://www.agmrc.org/agmrc/commodity/energy/biodiesel/biodiesel.htm>, accessed February 16, 2007.
[68] National Biodiesel Board, OEM Statement Summery Chart, available online at: http://www.biodiesel.org/using-biodiesel/oem-information/oem-statement-summary-chart.

Gasoline and diesel fuel, and their biofuel counterparts ethanol and biodiesel, are quality controlled on the basis of ASTM specifications. The establishment of the ASTM biodiesel specification was a major advance as manufacturers now have an industry accepted standard for quality. This new standard was an important factor in the recent increase in large-scale biodiesel production, as well as a greater acceptance of the biofuel by diesel engine manufacturers.

Biodiesel can be used in any standard diesel engine with little or no modification to the engine. However, because of its different properties, such as a higher cetane number, lower volatility, and lower energy content, biodiesel may cause some changes in the engine performance and emissions. These different properties can affect the injection timing and the diesel combustion process, causing lower power output. In contrast, biodiesel has a higher concentration of oxygen (by weight), which lends itself to more complete combustion, and biodiesel's higher cetane number provides smoother combustion and less engine noise. Biodiesel may also have a role as a diesel additive because of new low-sulfur rules for diesel.

The EPA implemented a rule[69] that all diesel fuel for on-road use must be ultra-low-sulfur (15 ppm) diesel as of June 2006 and low-sulfur (500 ppm) for non-road diesel in 2007. Cruise and container ships were required to phase in ultra-low sulfur diesel in 2011. Locomotives and smaller marine engines were required to use ultra-low sulfur diesel in 2012. Low-sulfur diesel has lower lubricity than typical diesel, and biodiesel can be used as an additive to increase lubricity.

8.5.2.4 Environmental Characteristics

When compared to petroleum diesel, biodiesel offers a variety of benefits. Testing has shown that biodiesel has lower sulfur emissions and particulate emissions than regular diesel fuel. While biodiesel yields significantly lower sulfur emissions, particulate matter, and unburned hydrocarbons, NO_x emissions can be higher for biodiesel than diesel, depending on the engine configuration. Not only does biodiesel emit few harmful gases when combusted, but in almost every circumstance, fewer greenhouse gases are emitted in the production and transportation of biodiesel than are released in the production, transportation, and refinement of petroleum diesel.[70]

8.5.2.5 Developmental Potential

In Alliant Energy's service territory, there are a total of 12 BQ-9000[71] biodiesel plants in operation (8 in Iowa, 2 in Minnesota, and 2 in Wisconsin). On a national level, production of biodiesel rose from 75 million gallons in 2005 to 1.1 billion gallons in 2011.[72] Approximately 14 percent of US soybean crops are used for biodiesel production.[73]

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[69] EPA Clean Diesel Web site, http://www.epa.gov/cleandiesel/, accessed January 2010.

[70] US Department of Energy, Alternative Fuels Data Center, http://www.afdc.energy.gov/vehicles/diesels_emissions.html, accessed June 26, 2013.

[71] National Biodiesel Accreditation Program, http://bq-9000.org/

[72] National Biodiesel Board Web site, http://www.biodiesel.org/production/production-statistics, accessed June 2013.

[73] Iowa State AgMRC, Soybean Oil and Biodiesel Usage Projections, http://www.extension.iastate.edu/agdm/crops/outlook/biodieselbalancesheet.pdf

The expiration of the biodiesel blender's tax credit at the end of 2013 and uncertainty about future RFS2 biodiesel mandates have contributed to an uncertain policy environment for the industry. In spite of these conditions, biodiesel production has remained steady from 2011 through early 2013.

8.6 WASTE-TO-ENERGY

WTE technologies can use a variety of refuse types and technologies to produce electrical power. The economic feasibility of a WTE facility is generally difficult to assess. Costs are highly dependent on transportation, processing, and tipping fees associated with a particular location. The values discussed in the following subsections should be considered representative of the technology at a generic site. According to the Energy Recovery Council (ERC), there are 86 WTE plants operating in the United States with a capacity to produce approximately 2,600 MW.[74] Of these 86 facilities, the ERC identifies 7 modular, small-scale WTE facilities in the United States (providing a total of 9.3 MW of generating capacity). However, the majority of these (i.e., 79 of the 86) WTE facilities generally fall into one of the following categories, which are characterized in the following discussion:

- Municipal solid waste mass burn.
- RDF.

8.6.1 Municipal Solid Waste Mass Burn

There are currently 64 WTE plants in the United States using mass burn technology to generate electricity. These plants burn municipal solid waste (MSW) in an "as-discarded" form, with minimal or no preprocessing of the waste. Since 1996, there has been very little activity for developing new MSW facilities. During this time, environmental opposition, related generally to emissions (of heavy metals, dioxins and furans, in particular) associated with combustion of MSW, has thwarted several attempts to develop WTE facilities in the United States. However, as landfill space in certain metropolitan areas is increasingly limited, more municipalities are investigating options to convert MSW to useful products, including Marion, Iowa.[75] Recently large-scale WTE projects announced in North America are listed in Table 8-16.

[74] Energy Recovery Council, "The 2010 ERC Directory of Waste-to-Energy Plants," available at: http://www.wte.org/userfiles/file/ERC_2010_Directory.pdf, accessed September 2013.
[75] Cedar Rapids Gazette, "Marion approves deal for garbage-to-ethanol facility," August 23, 2013. Accessed September 2013 at: http://thegazette.com/2013/08/23/marion-approves-deal-for-garbage-to-ethanol-facility/.

Table 8-16 Recently Announced WTE Projects

FACILITY	PROCESS	MSW PROCESSING CAPACITY (TONS/DAY)	GENERATION CAPACITY (MW)	ANNOUNCED COST	
				($ MILLION)	($/KW)
Covanta – Dunham/York	Mass Burn	400	17.5	260	14,900
Palm Beach Co. Solid Waste Authority	Mass Burn	3,000	95	668	7,030
Plasco -- Ottawa	Plasma Arc	375	Unspecified	Unspecified(1)	

Sources:

- Brinker, "Waste-to-Energy and Alternative Conversion Technologies – Experience and Opportunities." Municipal Waste Management Association (MWMA) 2012 Fall Summit, September 12, 2012.
- Babcock & Wilcox press release. "B&W Receives Full Notice to Proceed on Waste-to-Energy Plant Project in West Palm Beach, Fla." May 2, 2012. Available online at: http://www.babcock.com/news_and_events/2012/20120502a.html.
- CBC News. "Plasco and city ink garbage-to-energy deal." December 14, 2012. Available online at: http://www.cbc.ca/news/canada/ottawa/story/2012/12/14/ottawa-plasco-deal-imminent.html.

Notes:

1. Plasco and the City of Ottawa reached an agreement in which Plasco will receive where Plasco will receive a fee per tonne of waste handled. The agreement calls for the City of Ottawa to supply 109,500 tonnes of MSW per year over a term of 20 years. The announced MSW processing fee will be $83.25 per tonne. At the specified rate, the contract will have a value of approximately $180 million over the term of the 20-year contract.

8.6.1.1 Operating Principles

Converting refuse or MSW to energy can be accomplished by a variety of technologies. The degree of refuse processing determines the method used to convert MSW to energy. Refuse with limited processing to remove noncombustible and oversized items is typically combusted in a waterwall furnace similar to coal and biomass furnaces. The MSW is fed to a reciprocating grate in the boiler. The heat derived from combustion of MSW is used to generate steam in the walls of the furnace, which is converted to electrical energy via a steam turbine generator system. Other furnaces used in mass burning applications include refractory furnaces, rotary kiln furnaces, and controlled air furnaces for smaller modular units.

In the past 3 to 5 years, gasification processes have been proposed to process MSW, including plasma arc and modified fluidized bed processes. These technologies appear promising, but have not been demonstrated at commercial scale.

8.6.1.2 Applications

The avoided cost of waste disposal is a primary component in determining the economic viability of a WTE facility. High costs of land and waste transportation increase the feasibility of an MSW facility. The 64 operating mass burn plants have an annual capacity to process 22.8 million tons of waste per year. Large MSW facilities typically process 500 to 3,000 tons of MSW per day (the average amount produced by 200,000 to 1,200,000 residents), although there are a number of facilities operating in the 200 to 500 tons per day size range. The average design capacity of mass burn plants operating in the United States is about 1,000 tons of waste per day.[76]

8.6.1.3 Resource Availability

MSW plants are high capital cost projects that require an inexpensive and abundant fuel source to operate profitably. For this reason, plants are typically sited near large population centers or in areas of high priced land. The average American generates about 4 to 5 pounds of garbage per day, most of which would otherwise be sent to a landfill.[77]

8.6.1.4 Cost and Performance Characteristics

Table 8-17 provides the typical ranges of performance and cost for a facility burning 1,750 tons of MSW per day.

8.6.1.5 Environmental Impacts

One of the most significant environmental benefits of burning MSW is that it reduces landfill deposits. The combustion byproducts produced when MSW is burned are similar to those of most organic combustion materials. PM must be abated, and NO_x can form if the combustion temperature is too high. Unlike coal, the sulfur emissions from MSW are low. One MSW-emitted component that is atypical of fossil fuels is dioxin, which the EPA has ruled to be carcinogenic. This issue has been intensely debated in the scientific community and MSW projects face opposition as a result of the ruling.

8.6.1.6 Development Potential

There is some potential for MSW mass burn in Alliant Energy's region. Resource opportunities are limited to existing landfills, the most promising being those that are accepting the greatest amount of waste. The current waste acceptance rates of the local landfills were not available to Black & Veatch; therefore, the actual project potential is not known. The potential for MSW mass burn also depends on permitted emissions requirements for a new generation facility.

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[76] Energy Recovery Council, "The 2010 ERC Directory of Waste-to-Energy Plants," available at: http://www.wte.org/userfiles/file/ERC_2010_Directory.pdf, accessed September 2013.
[77] US EPA, available at http://www.epa.gov/waste/nonhaz/municipal/pubs/msw06.pdf, accessed January 2010.

Table 8-17 MSW Mass Burn Technology Characteristics

	50 MW WTE – MASS BURN
Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity, MW	50
Net Plant Heat Rate, Btu/kWh (HHV)	16,000
MSW Consumption, tpd	1,750
CF, percent	75 to 85
Economics, 2013$	
Overnight EPC Cost, $/kW	7,000 to 9,000
Owner's Cost Allowance, percentage of EPC Cost	25
Total Project Cost, $/kW	8,750 to 11,250
Fixed O&M, $/kW-yr	200 to 300
Variable O&M, $/MWh	10 to 15
Fuel Cost, $/MBtu	See Note 1.
Technology Status	
Commercial Status	Commercial
Installed US Capacity, MW	1,975
Project Duration, NTP to COD, months	42

Notes:
1. WTE facilities receive "tipping fees" to accept MSW. The tipping fees, which are generally determined based on tipping fees for MSW at nearby landfills, represent a significant revenue stream for economically viable WTE facilities.

8.6.2 Refuse-Derived Fuel

There are 15 operating RDF plants in the United States, with an annual capacity to process more than 6.5 million tons of waste. Of these facilities, there are ten that process and combust RDF to generate electricity. Five others are processing-only facilities, and another five are combustion only facilities.[78] Typical RDF facilities process 500 to 2,000 tons of RDF per day (the average amount produced by 200,000 to 800,000 residents). According to the Energy Resource Council, the average design capacity of RDF plants operating in the United States is approximately 1,400 tons of waste per day.

[78] Integrated Waste Services Association, "The 2007 IWSA Directory of Waste-to-Energy Plants," available at http://www.wte.org/userfiles/file/IWSA_2007_Directory.pdf, accessed January 2010.

8.6.2.1 Operating Principles

RDF is an evolution of MSW technology. Rather than burning trash in its bulky form, the MSW is processed and converted to fluff or pellets. This processing and conversion eases the handling and improves the combustibility of the MSW.

8.6.2.2 Applications

RDF is preferred over MSW in many WTE applications because it can be combusted with the same technology used to combust coal. Spreader stoker fired boilers, suspension fired boilers, fluidized bed boilers, and cyclone furnace units have all been utilized to generate steam from RDF. Fluidized bed combustors are often preferred for RDF energy applications because of their high combustion efficiency, capability to burn RDF with minimal processing, and inherent ability to effectively reduce NO_x and SO_2 emissions.

8.6.2.3 Cost and Performance Characteristics

Table 8-18 provides the typical ranges for performance and cost of an RDF facility processing and combusting 1,750 tons of waste per day.

Table 8-18 RDF Technology Characteristics (including RDF Processing)

	50 MW WTE – RDF
Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity, MW	50
Net Plant Heat Rate, Btu/kWh (HHV)	17,000
RDF Consumption, tpd	1,750
CF, percent	75 to 85
Economics, 2013$	
Overnight EPC Cost, $/kW	7,500 to 10,000
Owner's Cost Allowance, percentage of EPC Cost	25
Total Project Cost, $/kW	9,380 to 12,500
Fixed O&M, $/kW-yr	200 to 300
Variable O&M, $/MWh	10 to 15
Fuel Cost, $/MBtu	See Note 1.
Technology Status	
Commercial Status	Commercial
Installed US Capacity, MW	640
Project Duration, NTP to COD, months	42

Notes:
1. WTE facilities receive "tipping fees" to accept MSW. The tipping fees, which are generally determined based on tipping fees for MSW at nearby landfills, represent a significant revenue stream for economically viable WTE facilities.

8.6.2.4 Environmental Impacts

The use of RDF faces most of the same environmental obstacles as MSW and provides the same environmental benefits. However, RDF plants using fluidized bed technology can potentially achieve lower emissions than mass burn plants.

8.6.2.5 Development Potential

The resource potential for RDF was assumed to be the same as for MSW mass burn.

8.7 HYDROELECTRIC

Traditional hydroelectric power is generated by capturing the kinetic energy of water as it moves from a higher elevation to a lower elevation and using the water to drive a turbine and generator set. The amount of kinetic energy captured by a turbine is dependent on the head (vertical height the water is falling) and the flow rate of the water. Often, the potential energy of the water is increased by blocking and storing its natural flow with a dam. If a dam is not feasible, it is possible to divert water out of the natural waterway, through a penstock, and back to the waterway. Such "run-of-river" or "diversion" applications allow for hydroelectric generation without the impact of damming the waterway. Hydroelectric power is the largest source of renewable energy, comprising 963 GW of the installed capacity worldwide.[79] According to the DOE, the United States has an installed capacity of approximately 78 GW from conventional hydroelectric projects. Recent studies by the DOE indicate there is an additional unrealized capacity of up to 12.1 GW of hydroelectric power at the United State's combined 54,000 existing unpowered dams.[80]

8.7.1 Applications

Hydroelectric projects are categorized according to their size. Low power hydroelectric projects are generally below 2 MW, while small hydroelectric systems are between 2 and 30 MW. Medium hydroelectric project range up to 100 MW, and large hydro projects are greater than 100 MW. Medium and large hydroelectric projects are good resources for baseload power generation because of the ability to store a large amount of potential energy behind the dam and release it consistently throughout the year. Small hydroelectric projects generally do not have large storage reservoirs and are not dependable as dispatchable resources. A small (3 MW) hydroelectric system is shown in Figure 8-18.

[79] "Key World Energy Statistics 2012," *International Energy Agency, http://www.iea.org/publications/freepublications/publication/kwes.pdf*, accessed August 2013.
[80] "Non Powered Dam Potential", National Hydropower Assessment Program, http://nhaap.ornl.gov/content/non-powered-dam-potential, accessed August 2013.

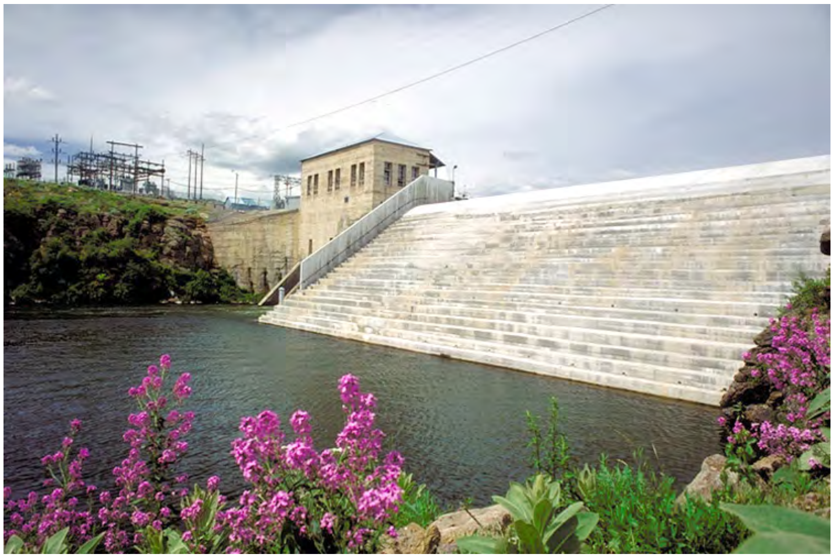


Figure 8-18 3 MW Hydroelectric Plant

8.7.2 Resource Availability

A hydroelectric resource can generally be defined as any flow of water that can be used to capture kinetic energy. Projects that store large amounts of water behind a dam regulate the release of the water through turbines over time and generate electricity regardless of the season. These facilities can generally serve baseloads. Pumped storage hydroelectric plants pump water from a lower reservoir to one at a higher elevation where it is stored for release during peak electrical demand periods. Run-of-river projects do not impound the water, but instead divert part or all of the current through a turbine to generate electricity. This technique is used at Niagara Falls to take advantage of the natural potential energy of the waterfall. Power generation at these projects varies with seasonal flows.

All hydroelectric projects are susceptible to drought. The variability in hydropower output is rather large, even when compared to other renewable resources. The aggregate CF for all hydroelectric plants in the United States has ranged from a high of about 42 percent to a low of 36 percent in just the last several years.[81]

Low hydropower potential also exists in conduit water systems. These include water distribution systems and irrigation canals. The potential for hydropower exists when these systems have excess head available due to geographic elevation changes within the systems. Often these systems include an energy dissipation valve to reduce the pressure and dissipate the excess energy in the water before it is released. If sufficient flow and head are available, then a viable low impact hydropower potential exists. These conduit hydropower systems have recently been addressed in the Hydropower Regulatory Efficiency Act (HR 216) and have been removed from

[81] Based on analysis of data from Energy Information Administration, *Renewable Energy Annual 2007*, release date: 2009.

FERC jurisdiction.[82] These low impact hydropower projects offer opportunities for distributed power generation at levels ranging from 100 kW to 1 MW.

8.7.3 Cost and Performance Characteristics

Hydroelectric power generation is regarded as a mature technology and is already established throughout the United States. It is not expected to experience any significant technical advancement due to its already high reliability and efficiency. Turbine efficiencies and costs have remained somewhat stable, but construction techniques and their associated costs continue to change. CFs are highly dependent on the resources and can range from 10 percent to more than 90 percent. More typical CFs are about 40 percent for run-of-river applications and around 60 percent for a facility with an impoundment structure. Capital costs also vary widely with site conditions.

Table 8-19 shows technology characteristics for typical hydroelectric projects. Because these characteristics are for typical, or generic, hydroelectric projects, they may not represent actual values associated with potential projects that Alliant Energy may consider. Characteristics are provided for new and incremental hydro. New would consist of a newly developed hydro project. An incremental project is one where upgrades to existing facility would be made to increase production.

[82] H.R. 267: Hydropower Regulatory Efficiency Act of 2013, 113th Congress. http://www.govtrack.us/congress/bills/113/hr267/text. Bill passed Congress, August 3, 2013 awaiting signature by President Obama.

Table 8-19 Hydroelectric Technology Characteristics

	HYDROELECTRIC – NEW	HYDROELECTRIC – INCREMENTAL
Performance		
Typical Duty Cycle	Varies with resource	Varies with resource
Net Plant Capacity, MW	2 to 30	Incremental
CF, percent	40 to 60	40 to 60
Economics, 2013$		
Total Project Cost, $/kW	2,650 to 5,620	700 to 3,400
Owner's Cost Allowance, percentage of EPC Cost	25	25
Total Project Cost, $/kW	3,310 to 7,020	875 to 4,250
Fixed O&M, $/kW-yr	11 to 74	11 to 74
Variable O&M, $/MWh	Included in Fixed O&M	
Applicable Incentives	$11/MWh PTC(1)	$11/MWh PTC(1)/30 percent ITC (for qualified facilities)
Technology Status		
Commercial Status	Commercial	
Installed US Capacity, MW(2)	77,930	
Project Duration, NTP to COD, months	24-36	12-18

Notes:
1. The duration of the eligibility period for the PTC is 10 years after the date the facility is placed in service.
2. US Hydroelectric Capacity, http://www.eia.doe.gov/cneaf/electricity/epa/epat1p1.html.

8.7.4 Environmental Impacts

The damming or diverting of rivers for hydroelectric applications may have significant environmental impacts. One major issue involves the migration of fish and disruption of spawning habits. For dam projects, one of the common solutions to this problem is the construction of "fish ladders" to aid the fish in bypassing the dam when they swim upstream to spawn.

A second issue involves flooding existing valleys that often contain wilderness areas, residential areas, or archeologically significant remains. There are also concerns about the consequences of disrupting the natural flow of water downstream and disrupting the existing ecosystems. The impacts of individual hydroelectric projects vary based on whether the project involves the construction of new dams or retrofits of existing dams (incremental). It should be noted that sites involving new dam construction may not be eligible to be considered renewable energy projects based upon most state's definition of renewable power.

8.7.5 Development Potential

The best sources for hydroelectric generation in Alliant Energy's service area are already developed. Additional hydroelectric generation in Alliant Energy's service region is most likely limited to the upgrade of existing facilities. There are a number of opportunities for increased production. Potential upgrade generation values were acquired from the Idaho National Engineering and Environmental Laboratory (INEEL) hydropower resource assessment data, which includes completely undeveloped sites as well as dams with and without generation capabilities. Depending on the location and individual project, the amount of increased generation could vary from several kilowatts to more than 100 MW. Of the 65 existing sites with undeveloped potential within the states of Iowa, Minnesota, and Wisconsin, there is an estimated capacity in the range of 240 to 400 MW. Some of the sites with highest potential exist at the existing lock and dam structures along the Mississippi River. Many of those sites are not yet developed but are under preliminary permit through FERC. The sites range in potential from 10 MW up to 78 MW according to the INEEL Hydropower database.

8.8 GEOTHERMAL

Geothermal power is produced by using steam or a secondary working fluid in a Rankine Cycle to produce electricity. Geothermal energy was first used to make electricity at the beginning of the 20th century. In 1904, Prince Piero Conti, owner of the Larderello fields in Italy, attached a generator to a natural-steam-driven engine which lit four light bulbs. This experiment led to the installation of the world's first geothermal power plant in 1911, with a capacity of 250 kilowatts. The government of New Zealand was the first significant producer of geothermal electricity, with the Wairakei power plant, which began generating approximately 150 MW in 1958. Shortly thereafter, the first power plants were installed at The Geysers in California, USA.

Today, 69 geothermal power facilities are in operation in over 20 countries around the world. There is a natural concentration of geothermal resources in regions characterized by volcanism, active tectonism, or both. For example, Indonesia and the Philippines have many large, high-temperature geothermal resources; about 11,000 MW of capacity are installed worldwide,[83] as shown in

Table 8-20. Within the United States (as of 2012), the Geothermal Energy Association reported an installed capacity of approximately 3,200 MW.

[83] Bertani, R. Geothermal Power Generation in the World, 2005-2010 Update Report. *Proc. World Geothermal Congress 2010*, Bali, Indonesia, 25-29 April 2010.

Table 8-20 Geothermal Capacity and Generation by Country (2010)

COUNTRY	GEOTHERMAL CAPACITY (MW)	ANNUAL GENERATION (GWH)
Australia	0.1	0.7
Austria	1	4
China (Tibet)	24	150
Costa Rica	166	1,131
El Salvador	204	1,422
Ethiopia	7	10
France*	18	15
Germany*	7.5	28
Guatemala	52	289
Iceland*	575	4,465
Indonesia	1,197	9,600
Italy*	842	5,376
Japan*	537	2,908
Kenya	167	1,430
Mexico*	958	6,618
New Zealand*	792	5,550
Nicaragua	88	310
Papua New Guinea (Lihir Island)	56	450
Philippines	1,904	10,311
Portugal (San Miguel Island)	29	175
Russia	82	441
Thailand	0.3	2
Turkey	82	490
USA*	3,102	15,009
Total- Global***	10,893	66,184

Source: Bertani, R. Geothermal Power Generation in the World, 2005-2010 Update Report. *Proc. World Geothermal Congress 2010*, Bali, Indonesia, 25-29 April 2010.

8.8.1 Applications

The most commonly used geothermal power generation technologies are direct steam (or dry steam), single-flash, dual-flash, and binary systems. In addition, efforts are underway to develop "enhanced geothermal" projects. The choice of technology is driven primarily by the temperature and quality of the steam/liquid extracted from the geothermal resource area. These geothermal technologies are classified as follows:

- **Direct Steam**: Where a vapor dominated resource is available, geothermal steam can be expanded directly in a steam turbine. Geothermal steam is used directly from the geothermal reservoir. It passes through steam strainers to remove rocks and particles and it enters the high pressure side of a reaction or impulse steam turbine. It then exhausts into a steam condenser. A surface type condenser can be used or direct contact condensers can be used where environmental requirements do not require treatment of non-condensable gases. Cooling water is typically circulated to the condenser from a wet or dry cooling tower. Since the steam condensate is not recirculated to a boiler (as in a conventional power plant), it is available as cooling-tower makeup. In fact, an excess of condensate (typically 10-20 percent) is available and usually reinjected back into the reservoir. The use of ACCs would allow for 100 percent reinjection, but they are generally uneconomic in a direct steam system. ACC systems are quite rare.
- **Single-Flash or Double-Flash**: Hot water resources above about 374°F need to be flashed to produce steam. Two-phase flow from the wells is directed horizontally and tangentially into a vertical cylindrical vessel called a cyclone separator. The liquid tends to flow circumferentially along the inner wall surface while the vapor moves to the top where it is removed. The steam transmission pipelines are essentially the same as for the direct-steam plant. The balance of plant is also nearly identical to the dry steam plant, the main difference being the much greater amount of liquid that must be handled.

  A single flash plant produces about 30 times more waste liquid than a direct steam plant. The single-flash plant can reinject about 85 percent of the produced mass as compared to 15 percent for a direct-steam plant. A dual-flash system is normally used for geothermal fluids in the range of 240°C to 320°C. About 20 to 25 percent more power can be generated from the same flow rate of geothermal fluids by using a dual-flash technology as compared to single-flash. The secondary, low-pressure steam produced by separating the steam from the brine at a lower pressure is sent either to separate low pressure turbine or to an appropriate stage of the main turbine.

  The principles of operation of a dual-flash plant are similar to the single-flash plant. The dual-flash plant is somewhat more expensive due to the extra equipment associated with the flash vessel, the piping system, and additional control valves, as well as the more elaborate or extra turbine.

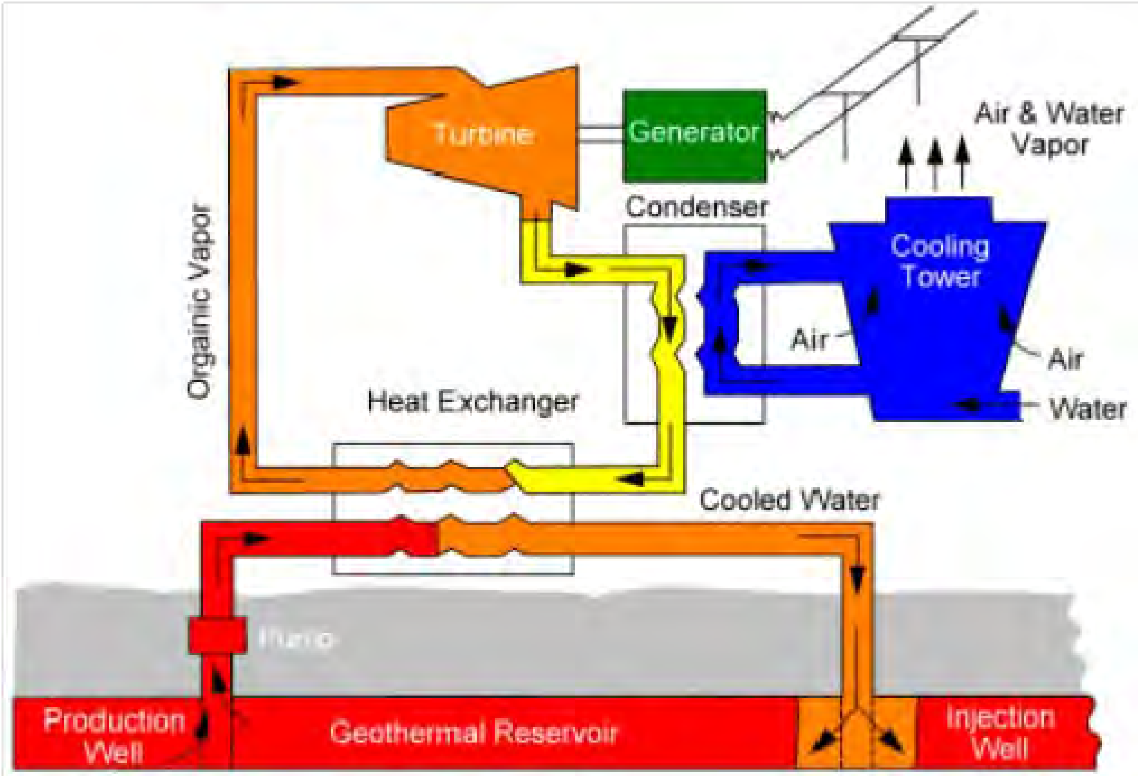
- **Binary**: For lower temperature hot water, below 190°C, the use of a secondary low boiling point fluid (hydrocarbon) is required to generate the vapor in a binary or organic Rankine cycle plant. In a binary plant, the thermal energy in the geothermal brine is transferred in a heat exchanger to a secondary working fluid for use in a fairly conventional Rankine cycle. The brine itself does not contact moving parts of the power plant, thus minimizing the potential problems (such as scaling, corrosion or erosion).

  Binary plants may be especially advantageous for low brine temperatures (less than about 170°C) or for brines with high dissolved gases or high corrosion or scaling potential. The latter problems are usually exacerbated when the geothermal liquid flashes to vapor as typically occurs in a self-flowing production well. Downhole pumps located below the flash level in the well can prevent flashing by raising the pressure above saturation pressure for the liquid temperature.

  Most binary plants operate on pumped wells and geothermal fluid remains in the liquid phase throughout the plant, from production wells through the heat exchangers to the injection wells. Dry cooling is typically used with a binary plant to avoid the necessity for make-up water required for a wet cooling system. Because of chemical impurities, the waste geothermal fluid is not generally suitable for cooling tower make-up.

  There is a wide range of candidate working fluids for the closed power cycle. The designer generally tries to achieve good thermodynamic match to the particular geothermal temperature. The optimal fluid gives a high utilization efficiency with safe and economical operation. A binary geothermal system is shown in Figure 8-19.

- **Enhanced Geothermal (including "hot dry rock" or "partly molten rock")**: Defined as heat stored in rocks within about 6 miles of the surface, from which energy cannot be economically extracted by natural hot water or steam. These hot rocks have a relatively low proportion of pore space or fracture, and therefore contain little water. In order to extract heat, the rock is hydraulically fractured and cold water is circulated through the hot fractured rock to extract heat. While enhanced geothermal projects are currently being demonstrated around the world (including the Newberry Volcano Enhanced Geothermal Systems [EGS] demonstration near Bend, Oregon) this technology needs further demonstration and commercialization.



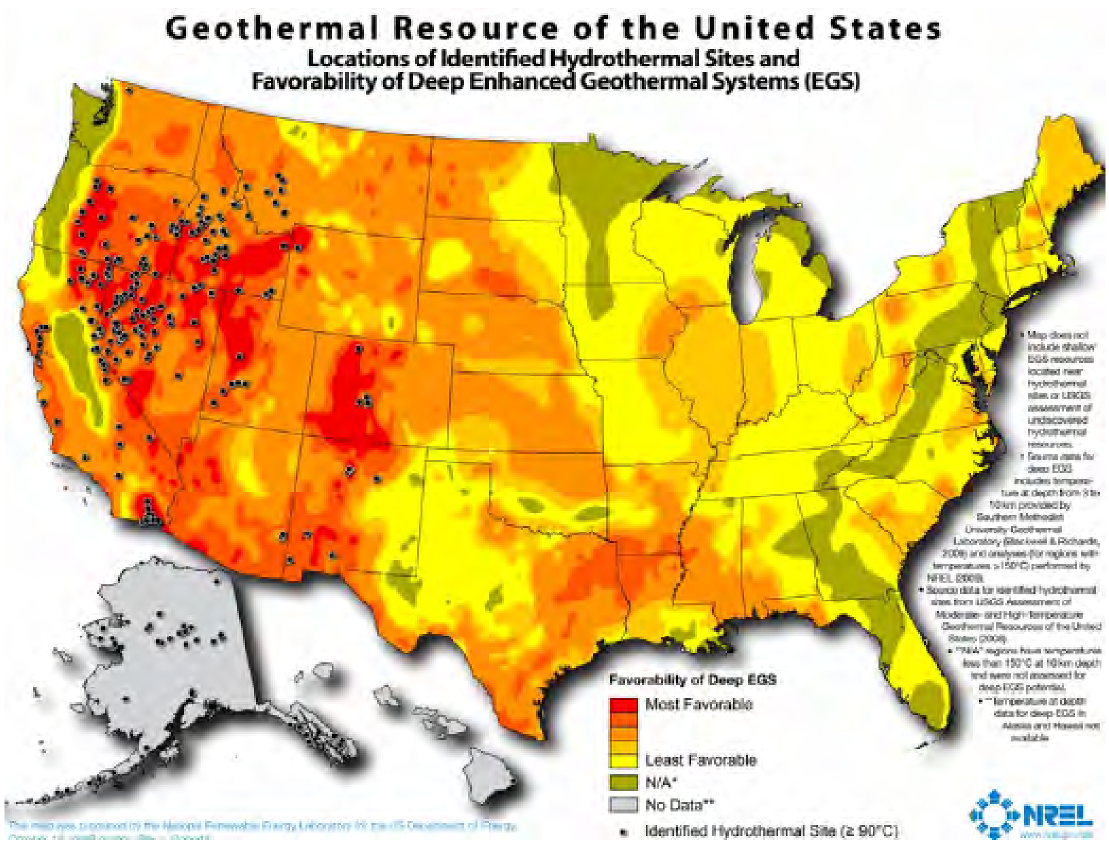
Source: Colorado Department of Natural Resources

Figure 8-19 Binary Geothermal System

In addition to generating electricity and direct space heating applications, hot water and saturated steam from a geothermal resource can be used for a wide variety of process applications. These applications include fish hatching, mushroom growing, refrigeration, wool washing and drying, light aggregate cement slab drying and curing, sugar refining evaporation, food canning, timber drying, and paper pulp digestion.

8.8.2 Resource Availability

Geothermal power is limited to locations with geothermal pressure reserves. Well temperature profiles determine the potential for geothermal development and the type of geothermal power plant installed. High energy sites are suitable for electricity production, while low energy sites are suitable for direct heating. A geothermal field's power production capability may decline over time. Most of the geothermal resources in the United States are concentrated in the west and southwest parts of the country (refer to Figure 8-20).



(Source: C. Augustine, "Updated US Geothermal Supply Curve," National Renewable Energy Laboratory Proceedings, Thirty-Fifth Workshop on Geothermal Resource Engineering, Stanford University, SGP-TR-188, February 2010).

Figure 8-20 Geothermal Resource of the United States

8.8.3 Cost and Performance Characteristics

For representative purposes, a binary cycle power plant is characterized in Table 8-21. In a binary cycle plant, a working fluid is boiled by heat transferred from a geothermal source across a heat exchanger and then expanded through a turbine. Capital costs of geothermal facilities can vary widely since the drilling of individual wells can cost between $1 million and $4 million, and the number of wells drilled depends on the success of finding the resource. Drilling costs typically comprise 35 to 45 percent of the total capital cost of a geothermal power generating facility.

Table 8-21 Geothermal Technology Characteristics

	30 MW GEOTHERMAL
Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity, MW	30
CF, percent	70 to 90
Economics, 2013$	
Overnight EPC Cost, $/kW	4,000 to 8,000
Owner's Cost Allowance, percentage of EPC Cost	20
Total Project Cost, $/kW	4,800 to 9,600
Fixed O&M, $/kW-yr	170 to 330
Variable O&M, $/MWh	Included in Fixed O&M
Technology Status	
Commercial Status	Commercial
Installed US Capacity, MW(1)	3,180
Project Duration, NTP to COD, months	18

Notes:
1. "Geothermal Power Plants - USA," *Geothermal Energy Association*, http://geo-energy.org/plants.aspx, accessed August 7, 2013.

8.8.4 Environmental Impacts

Geothermal energy has relatively low land use compared to many other renewable energy technologies. Land requirements for a geothermal power plant depend on the properties of the geothermal reservoir, power plant capacity, type of energy conversion system, type of cooling system, arrangement of wells and piping systems, and substation and auxiliary building needs. Hence, a representative value for geothermal land use is difficult to determine. Estimates for geothermal direct land use range from approximately 350 MW/km^2 (900 MW/mi^2) to approximately 830 MW/km^2 (2,150 MW/mi^2).[84,85]

Water consumption is primarily a function of the type of cooling system used. Dry cooling can mitigate the need for makeup water.

Dissolved minerals and hazardous noncondensable gases in geothermal fluids can be an environmental concern if not handled correctly (fluid re-injection addresses many concerns).

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[84] Kagel, et al., "A Guide to Geothermal Energy and the Environment," Geothermal Energy Association, 2007.
[85] DiPippo, *Geothermal Power Plants – Principles, Applications and Case Studies*, 2008.

Geothermal power plants with modern emissions control technologies have minimal environmental impact. They emit less than 0.2 percent of the CO_2, less than 1 percent of the SO_2, and less than 0.1 percent of the particulates of the cleanest fossil fuel (i.e. coal-fired) plant. Binary geothermal facilities have less environmental impact than direct steam or flash plants since the geothermal fluid is reinjected deep underground without exposure to groundwater or the above surface environment.

There is the potential for geothermal production to cause ground subsidence. Subsidence, which is a slow sinking of the land surface, can occur at geothermal developments. Reservoir fluids under hydrostatic pressure help support the overburden of the rock formation. Withdrawal of this fluid may leave some overburden unsupported and result in surface sinking.[85] Reservoir-temperature decline can also lead to contraction and subsidence. This is rare in dry steam resources but more likely in liquid-dominated fields. However, carefully applied re-injection techniques can effectively mitigate this risk.

The potential for increasing seismic activity is being investigated for enhanced geothermal systems. Most developed geothermal resources are located in tectonically active areas, making it difficult to separate naturally occurring tectonic activity from development-related events. Induced, low-magnitude, seismic events can result from production and injection operations. Development of EGS involves stimulating subsurface rock to open and extend existing fracture networks; induced seismicity is one result of this reservoir creation process. Although induced seismicity is a special concern for geothermal development in urban areas, its direct effect on the surrounding environment is normally negligible and can be successfully managed through proactive risk communication, proper siting, technology research and development, best practice methodology implementation, monitoring, and mitigation strategies.

Even with careful site selection, geothermal projects are likely to have some impact on the surrounding community. These impacts can be minimized by choosing plant designs tailored to the project area and resource, such as choosing power plant cooling technologies most appropriate for a site location and designing the plant to eliminate any non-condensable gases associated with a resource, and by engaging the community to educate and minimize induced seismicity impacts.

8.8.5 Development Potential

The potential for electricity generation from geothermal energy is poor in the Alliant Energy territory. There are no significant geothermal sources in the region, although there is a low-temperature source in a region of eastern Iowa and southwest Wisconsin which could potentially be used directly for heating or various process applications. Heat pumps do not require high-temperature geothermal sources and could be used for small-scale heating and cooling virtually anywhere in the region. Figure 8-20 shows the location of identified hydrothermal sites, the co-located, near-hydrothermal field EGS resources, and the favorability of the deep EGS resources by location. The undiscovered hydrothermal resources and other geothermal resources, such as co-produced fluids, are not represented.

Appendix A. Nuclear Reactor Radionuclide Emissions

Radiological emission are closely monitored and regulated by the US Nuclear Regulatory Commission. Table A-1 and A-2 identify expected normal airborne and liquid radionuclide source terms. See US NRC Regulatory Guide 1.70 for accident conditions.

Table A-1 Expected Annual Average Release of Airborne Radionuclides as Determined by the PWR-Gale Code, Revision 1 (Release Rates in CI/YR)

NOBLE GASES (1)	WASTE GAS SYSTEM	BUILDING/AREA VENTILATION			CONDENSER AIR REMOVAL SYSTEM	TOTAL
		CONT.	AUXILIARY BUILDING	TURBINE BUILDING		
Kr-85m	0.	3.0E+01	4.0E+00	0.	2.0E+00	3.6E+01
Kr-85	1.65E+02	2.4E+03	2.9E+01	0.	1.4E+01	4.1E+03
Kr-87	0.	9.0E+00	4.0E+00	0.	2.0E+00	1.5E+01
Kr-88	0.	3.4E+01	8.0E+00	0.	4.0E+00	4.6E+01
Xe-131m	1.42E+02	1.6E+03	2.3E+01	0.	1.1E+01	1.8E+03
Xe-133m	0.	8.5E+01	2.0E+00	0.	0.	8.7E+01
Xe-133	3.0E+01	4.5E+03	7.6E+01	0.	3.6E+01	4.6E+03
Xe-135m	0.	2.0E+00	3.0E+00	0.	2.0E+00	7.0E+00
Xe-135	0.	3.0E+02	2.3E+01	0.	1.1E+01	3.3E+02
Xe-138	0.	1.0E+00	3.0E+00	0.	2.0E+00	6.0E+00
					Total	1.1E+04
Additionally:						
H-3 released via gaseous pathway						350
C-14 released via gaseous pathway						7.3
Ar-41 released via containment vent						34

IODINES(1)	FUEL HANDLING AREA(2)	BUILDING/AREA VENTILATION			CONDENSER AIR REMOVAL SYSTEM	TOTAL
		CONT.	AUXILIARY BUILDING	TURBINE BUILDING		
I-131	4.5E-03	2.3E-03	1.1E-01	0.	0.	1.2E-01
I-133	1.6E-02	5.5E-03	3.8E-01	2.0E-04	0.	4.0E-01

RADIONUCLIDES(1)	WASTE GAS SYSTEM	BUILDING/AREA VENTILATION			TOTAL
		CONT.	AUXILIARY BUILDING	FUEL HANDLING AREA(2)	
Cr-51	1.4E-05	9.2E-05	3.2E-04	1.8E-04	6.1E-04
Mn-54	2.1E-06	5.3E-05	7.8E-05	3.0E-04	4.3E-04
Co-57	0.	8.2E-06	0.	0.	8.2E-06
Co-58	8.7E-06	2.5E-04	1.9E-03	2.1E-02	2.3E-02
Co-60	1.4E-05	2.6E-05	5.1E-04	8.2E-03	8.7E-03
Fe-59	1.8E-06	2.7E-05	5.0E-05	0.	7.9E-05
Sr-89	4.4E-05	1.3E-04	7.5E-04	2.1E-03	3.0E-03
Sr-90	1.7E-05	5.2E-05	2.9E-04	8.0E-04	1.2E-03
Zr-95	4.8E-06	0.	1.0E-03	3.6E-06	1.0E-03
Nb-95	3.7E-06	1.8E-05	3.0E-05	2.4E-03	2.5E-03
Ru-103	3.2E-06	1.6E-05	2.3E-05	3.8E-05	8.0E-05
Ru-106	2.7E-06	0.	6.0E-06	6.9E-05	7.8E-05
Sb-125	0.	0.	3.9E-06	5.7E-05	6.1E-05
Cs-134	3.3E-05	2.5E-05	5.4E-04	1.7E-03	2.3E-03
Cs-136	5.3E-06	3.2E-05	4.8E-05	0.	8.5E-05
Cs-137	7.7E-05	5.5E-05	7.2E-04	2.7E-03	3.6E-03
Ba-140	2.3E-05	0.	4.0E-04	0.	4.2E-04
Ce-141	2.2E-06	1.3E-05	2.6E-05	4.4E-07	4.2E-05

Notes:

1. The appearance of 0. in the table indicates less than 1.0 Ci/yr for noble gas or less than 0.0001 Ci/yr for iodine. For particulates, release is not observed and assumed less than 1 percent of the total particulate releases.
2. The fuel handling area is within the auxiliary building but is considered separately.
3. Reference: APP-0000-X-001, Westinghouse AP1000 Siting Guide: Site Information for Early Site Permit, Non-Proprietary, April 2003.

Table A-2 Releases to Discharge Canal (Ci/yr)
Calculated by GAYLE Code

NUCLIDE	SHIM BLEED	MISC. WASTES	TURBINE BUILDING	COMBINED RELEASES	TOTAL RELEASES(1)
			Corrosion and Activation Products		
Na-24	0.00053	0.0(2)	0.00008	0.00061	0.00163
Cr-51	0.00068	0.0	0.0	0.00070	0.00185
Mn-54	0.00048	0.0	0.0	0.00049	0.00130
Fe-55	0.00037	0.0	0.0	0.00037	0.00100
Fe-59	0.00008	0.0	0.0	0.00008	0.00020
Co-58	0.00125	0.0	0.00001	0.00126	0.00336
Co-60	0.00016	0.0	0.0	0.00017	0.00044
Zn-65	0.00015	0.0	0.0	0.00015	0.00041
W-187	0.00004	0.0	0.0	0.00005	0.00013
Np-239	0.00008	0.0	0.0	0.00009	0.00024
			Fission Products		
Br-84	0.00001	0.0	0.0	0.00001	0.00002
Rb-88	0.00010	0.0	0.0	0.00010	0.00027
Sr-89	0.00004	0.0	0.0	0.00004	0.00010
Sr-90	0.0	0.0	0.0	0.0	0.00001
Sr-91	0.00001	0.0	0.0	0.00001	0.00002
Y-91m	0.0	0.0	0.0	0.00001	0.00001
Y-93	0.00003	0.0	0.0	0.00002	0.00009
Zr-95	0.0010	0.0	0.0	0.00005	0.00023
Nb-95	0.00009	0.0	0.0	0.00005	0.00021
Mo-99	0.00028	0.0	0.00001	0.00013	0.00057
Te-99m	0.00027	0.0	0.00001	0.00013	0.00055
Ru-103	0.00183	0.00001	0.00002	0.00185	0.00493
Rh-103m	0.00183	0.00001	0.00002	0.00185	0.00493
Ru-106	0.02729	0.00011	0.00021	0.02761	0.07352
Rh-106	0.02729	0.00011	0.00021	0.02761	0.07352
Ag-110m	0.00039	0.0	0.0	0.00039	0.00105
Ag-110	0.00005	0.0	0.0	0.00005	0.00014
Te-129m	0.00004	0.0	0.0	0.00005	0.00012
Te-129	0.00006	0.0	0.0	0.00006	0.00015
Te-131m	0.00003	0.0	0.0	0.00003	0.00009
Te-131	0.00001	0.0	0.0	0.00001	0.00003
I-131	0.00512	0.00004	0.00015	0.00531	0.01413
Te-132	0.00009	0.0	0.0	0.00009	0.00024
I-132	0.00054	0.00001	0.00007	0.00062	0.00164
I-133	0.00211	0.00003	0.00038	0.00252	0.00670
I-134	0.00030	0.0	0.0	0.00031	0.00081
Cs-134	0.00370	0.00001	0.00002	0.00373	0.00993
I-135	0.00144	0.00002	0.00041	0.00187	0.00497
Cs-136	0.00023	0.0	0.0	0.00024	0.00063
Cs-137	0.00496	0.00001	0.00003	0.00500	0.01332
Ba-137m	0.00464	0.00001	0.00002	0.00468	0.01245
Ba-140	0.00203	0.00001	0.00003	0.00207	0.00552
La-140	0.00272	0.00002	0.00005	0.00279	0.00743
Ce-141	0.00003	0.0	0.0	0.00004	0.00009
Ce-143	0.00006	0.0	0.00001	0.00007	0.00019
Pr-143	0.00005	0.0	0.0	0.00005	0.00013
Ce-144	0.00117	0.0	0.00001	0.00119	0.00316
Pr-144	0.00117	0.0	0.00001	0.00119	0.00316
All others	0.00	0.0	0.0	0.00001	0.00002
Total (except tritium)	0.09398	0.00043	0.00182	0.09623	0.25623
Tritium release		1010 curies per year			

Notes:
1. The release totals include an adjustment of 0.16 Ci/yr added by PWR-GALE Code to account for anticipated operational occurrences such as operator errors that result in unplanned releases.
2. An entry of 0.0 indicates that the value is less than 10E-05 Ci/yr.
3. Reference: APP-0000-X-001, Westinghouse AP1000 Siting Guide: Site Information for Early Site Permit, Non-Proprietary, April 2003.

Appendix B. Solar PV Modeling Design Basis and Results

Design Basis

Project Information			Notes:
Client:	Alliant Energy		
Project:	Technology Characterization Study		
Task:	Solar PV Section Update		*Update to 2010 study*
Project and Phase:	179934.0042		
Level of Analysis:	Conceptual		

Weather/Solar Resource			Notes:
Location(s):	Waterloo, IA	Madison, WI	*Per Client request*
Lat/Long:	42.33° N / 92.24° W	43.80° N / 89.20° W	
Data Souce:	TMY2		
Soiling:	3% annually		*B&V assumption, for conceptual level analysis*

System Summary		Notes:
AC Capacity (kW):	10,000	*Per Client request*
STC Capacity (kW):	12,956	
Tilt:	30 degrees	*B&V assumption*
Azimuth:	0 degrees	*B&V assumption*
Mounting:	Fixed tilt	*Per Client request*
Orientation:	2 in portrait	*B&V assumption*
Pitch (m):	9.0	*B&V assumption*
Collector Height:	3.9	*B&V assumption*
GCR:	43%	*B&V assumption*
Module Make:	Trina Solar, TSM-295 P14	*Or equivalent, per Client request*
Module Rating (Wp):	295	
Modules per String:	18	*B&V assumption*
Module Voc:	45.2	
String Voc:	813.6	
Inverter:	SMA 500CP-US	*B&V assumption*
Inverter Rating (kW ac):	500	
Strings per Inverter:	122	*B&V assumption*
ILR:	1.30	*B&V assumption*
Number of Inverters:	20	
Number of Strings:	2,440	
Number of Modules:	43,920	

Other Assumptions	
Site:	Suitable land area for PV development, requiring minimal site work
Equipment:	Equipment specified above is considered to be representative of a typical utility scale installation
DC Voltage:	Assumes 1000 Vdc system

Performance Summary

Results Summary	Waterloo, IA	Madison, WI	*Notes:*
System dc Capacity (MWp)	12.96	12.96	*System dc Capacity = Sum of Module STC Rating*
System ac Capacity (MWac)	10.00	10.00	*System ac Capacity = Sum of Inverter Nameplate Rating*
Annual Generation (MWh/year)	17,963	17,651	*First year output, does not include degradation*
Capacity Factor DC	15.8%	15.6%	*Capacity Factor DC = (Annual Generation / System dc Capacity)*
Capacity Factor AC	20.5%	20.1%	*Capacity Factor AC = (Annual Generation / System ac Capacity)*
Annual Yield (kWh/kWp)	1,386	1,362	*Annual Yield = (Annual Generation / System dc Capacity)*
Performance Ratio	82.2%	82.0%	*Performance Ratio = [Annual Yield / (Annual Measured-in-Plane Insolation / STC Reference Irradiance)]*

Loss and Gain Estimates		Waterloo, IA	Madison, WI	*Units:*
	Global Horizontal Radiation	1,450	1,436	*[kWh/m² /year]*
	Transposition Model	Perez	Perez	
Available Energy on Collector Plane (POA)	Transposition Factor	16.50%	16.20%	
	Global Inclined Radiation	1,690	1,669	*[kWh/m² /year]*
	Internal Shadings	-3.00%	-3.10%	
	External Shadings	0.00%	0.00%	
	Incident Angle Modifier Loss	-2.80%	-2.80%	
	Effective Global Inclined Radiation	1,594	1,573	*[kWh/m² /year]*
	Loss due to Irradiance Level	-1.40%	-1.40%	
	Loss Due to Temperature	-1.90%	-1.70%	
Available Energy at Inverter Output Terminals	Soiling	-3.10%	-3.10%	
	Module Quality	-0.40%	-0.40%	
	Module Mismatch	-1.00%	-1.00%	
	DC Wire Loss	-1.20%	-1.20%	
	Inverter Efficiency Loss	-1.90%	-1.90%	
	Inverter Clipping	-0.10%	-0.30%	
	Energy at Output of Inverter Blocks	1,430	1,409	*[kWh/kWp/yr]*
	Transformer	-1.00%	-1.00%	
Available Energy at Utility Grade Meter	AC Wire Losses	-0.50%	-0.50%	
	Auxiliary Loads	(67)	(67)	*[MWh/yr]*
	Availability	-1.00%	-1.00%	
	Adjustment of TMY to Long term Mean	-0.20%	-0.40%	
	Energy at Revenue Grade Meter [1]	1,386	1,362	*[kWh/kWp/yr]*
Annual Loss	Degradation [2]	-0.70%	-0.70%	

[1] Values are for the first year of energy production, excluding long-term degradation.

[2] Degradation should be applied to production values for every year beyond the first year.